ATTACHMENT D

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Entergy

PHASE II
TRANSMISSION STUDY REPORT

PREPARED IN RESPONSE TO THE LOUISIANA PUBLIC SERVICE COMMISSION ORDER NO. U-23356-SUBDOCKET A

ENTERGY SERVICES, INC.

JULY 3, 2003

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Executive Summary

This study, referred to as the Phase II Transmission Study, explored Entergy System ("System") transmission expansion alternatives aimed at alleviating internal and external interface limitations associated with the System's control area, with a focus on the Amite South region of Entergy. Entergy Services, Inc. ("ESI" or the "Company") on behalf of Entergy Louisiana, Inc. ("ELI") undertook this study at the request of the Louisiana Public Service Commission ("LPSC" or the "Commission").

The Phase II Study took just over one year to complete. Some of this time was required due to the conversion to PROMOD IV, which program was needed to perform the detailed combination of transmission and production costing analyses. However, the study process itself involved a countless number of computer runs. The production cost analysis was the primary focus of two individuals over the past year. Countless iterations were prepared to ensure that the appropriate transmission projects were analyzed. Each study required twenty hours of computer time, roughly five hours of set-up time and ten hours for post processing activities. The Company recommends that the results of this study be rolled into the transmission planning process. This would allow the impact of the projects on the reliability of the System to be more fully analyzed and understood, and would facilitate further consideration of their implementation based on current data and forecast.

The transmission expansion alternatives that have been identified in this study include ten transmission projects located across all state jurisdictions. These projects are focused on alleviating flow restrictions associated with the eleven most limiting transmission facilities defined during the study process. Two of the projects involve 230 kilovolt ("kV") transmission line construction in the state of Louisiana. These two lines, from the Coly substation to the Vignes substation and from the Conway substation to the Bagatelle substation, would improve the Amite-South interface capability, and thus would improve reliability to customers within the Amite-South area.

Overall, the study shows positive results for the Entergy System. The cost-benefit analysis associated with the implementation of the all ten projects yields an overall net benefit of $119 million to Entergy's customers over the study period. The ten transmission projects identified in this study would cost approximately $107 million and would need to be completed by 2006 in order to obtain the estimated benefits discussed above. In addition, subset analyses were also performed in attempt to identify the potentially more cost effective sets of projects. This cost-benefit analysis shows that certain subset of the full ten projects (*i.e.,* Subsets A, B and C) result in even higher overall benefit to the Entergy's customers.

The transmission revenue requirement analysis, summarized in the following table, shows the net present value from 2004 through 2026 for the ten transmission projects and subsets of those projects. The net present value calculation uses an 8.5% discount rate, which is based on an approximation of net of tax overall rate of return. The Study assumed EGSI-Texas enters deregulation by January 1, 2004. A net increase in costs is shown in parentheses, while net benefits are shown as positive numbers.

Net Impact ($000's)

Cases	EAI	ELI	EMI	ENOI	EGSI-LA	EGSI-TX	Entergy
Case with ten projects	($25,270)	$82,546	$31,045	$12,989	$33,440	($14,902)	$119,848
Subset A	$9,705	$84,251	$28,359	$12,591	$31,963	$5,143	$172,011
Subset B	($7,840)	$88,897	$32,473	$13,481	$36,122	$5,800	$168,933
Subset C	($15,813)	$97,143	$37,102	$16,202	$42,491	($7,226)	$169,901

This study measured the long-term benefits of the possible transmission expansion alternatives using the PROMOD IV Hourly Monte Carlo ("HMC") production cost model, configured with a detailed representation of the Entergy Transmission System. This analysis modeled both merchant generation that was already in commercial operation and merchant generation that was expected to be in commercial operation by the summer of 2004. The study also considered all transmission improvements committed to by the merchant generators or by the System to meet its native load requirements. Benefits and costs were calculated for 10 years (from January 2003 through December 2012) using the PROMOD IV HMC model and were interpolated for the remaining years, through 2026.

The results of this study are based on the list of assumptions that are attached as Appendix D. These results could be impacted by any changes to the following key input assumptions:

- The amount of merchant capacity that is available to serve the System's load.
- The fuel prices (gas, oil, coal, and nuclear) and unit characteristics (heat rates, forced outage rates, etc.) assigned to Entergy's existing capacity.
- The External Market Prices ("EMP") that are used in PROMOD IV HMC to represent the adjacent power markets of Southern Company, the Midwest, and TVA.
- The cost of the transmission projects and the proposed schedule for completing the transmission expansion alternatives.
- The number of monitored lines and contingencies evaluated within the PROMOD IV HMC program.

I. Phase II Study Background

In LPSC Order No. U-23356-A, dated April 12, 2002, the Commission directed the Company to perform a cost-benefit analysis (hereinafter referred to as the "Phase II Study") based on the transmission screening study results previously presented in LPSC Docket No. U-23356 (hereinafter referred to as the "Phase I Study").

Entergy Louisiana, Inc. presented a Draft Work Plan for the Phase II Study in the Technical Conference organized by the LPSC on May 21, 2002 and subsequently filed a Response to the Comments that had been filed by Intervenors on the Draft Work Plan. Upon reviewing all the filings made by Intervenors and the Company, the LPSC Staff requested that ELI submit a Detailed Work Plan, which was submitted on November 8, 2002.

The Detailed Work Plan was provided for periodic updates to the LPSC Staff on the study's progress. The Company has done so on various occasions and has posted non-confidential information on the public portion of Entergy's Open Access Same-Time Information System ("OASIS") web site.

A. Entergy System Overview

The Entergy Transmission System (the "System") is an interconnected network of electric transmission facilities consisting of approximately 16,000 miles of lines spanning 112,000 square miles of service area in four states. The Entergy System has seventy-four external tie lines with fourteen adjacent utility systems, in voltages ranging from 69 kV to 500 kV. The combined capacity of the seventy-four external tie lines amounts to approximately 30,000 megawatts ("MW"), which is the sum of their thermal capacities. The maximum simultaneous import capability into the Entergy Transmission System is approximately 3,900 MW, and the simultaneous export capability of the System is approximately 2,600 MW.

The disparity between the total capacity of the external ties and the transfer capability across the external interfaces results from the nature of physical flows on an electrical network, including the resultant flows following a component outage. The System must be able to withstand the loss of the most critical transmission line without the resulting flows overloading any of the remaining transmission lines. The same situation applies to the electrical network internal to the System. If these transfer capabilities are not adhered to, transactions that exceed the first operating contingency might be scheduled across interfaces. If that were to occur, schedules accepted by the System operator would not be feasible and could not be accommodated. Therefore, transfer capability is dependent upon both System topology and industry rules that govern System operations.

Much of the Entergy Transmission System as it exists today evolved from five individual systems, which were constructed by the five separate Operating Companies that now make up the Entergy System. Many of the existing transmission corridors were acquired 50 to 100 years ago and were developed in order to enable local load to be served by local generation within each of the Operating Companies. The lack of transmission interconnections between Operating Companies as well as between Entergy and its neighbors resulted in what is seen today as limitations to the movement of power between some geographical areas of the Company and between Entergy and its neighbors. The System has been upgraded over the last 100 years, but until the addition of the 500 kV extra high voltage system ("EHV") the basic topology of the System did not deviate much from the lines as originally laid out. Local geography and jurisdictional boundaries combined with load and generation placement to define the topology of the transmission grid, which has defined transfer capabilities.

The addition of the 500 kV backbone to the Entergy System in the 1960s enhanced transfer capabilities across the jurisdictional and geographical boundaries, which is why the Company has the magnitude of transfer capabilities that exist today. However, it was the focus of the Phase I and Phase II Transmission Studies to see if the System would benefit by increasing those transfer capabilities.

For reference, a map of the Entergy transmission network is provided in Appendix A.

B. Merchant Generation Development

Since 1998, over 180 requests totaling over 100,000 MW of generation capacity have been made by merchant generation developers to study the interconnection of their facilities to Entergy's Transmission System. Over half of these requests were for locations within the state of Louisiana. A significant portion of these requests were carried through to the construction phase. To date, merchant generation developers have completed construction of over 13,000 MW within the Entergy Transmission System foot print, with an additional 4,500 MW still under construction.

While there are relatively few requests being submitted today for the interconnection of new generators to the Entergy System, the facilities that have interconnected present a challenge to the existing Transmission System, which was constructed over decades to accommodate the System's generation mix and native load requirements. The increased demand by the merchant generators to utilize the transmission grid has resulted in greater power flows across the transmission network than were ever contemplated. These additional power flows have caused new transmission bottlenecks that limit the movement of power across the Transmission System to become apparent.

Merchant generation was recognized to have a significant impact on the operation of the System. The Phase II analysis included all merchant generation that was in commercial operation or was expected to be in commercial operation by the summer of 2004.

C. Phase I Transmission Study

Pursuant to LPSC Order No. U-23356, and more specifically Finding of Fact No.192 adopted in that Order, the Company performed the Phase I Transmission Study in 2001. The study identified transmission lines that limited the flow of energy between four discrete areas of the Company, the extent of those limits, and the contingencies that caused the System to run up against them. Projects were identified in the study that alleviated the identified transmission constraints, and a cost-benefit analysis was performed based on the cost of the identified projects versus the projected benefits derived from estimated fuel savings.

Approximately 6,300 MW of merchant generation was under construction in the service area at the time of the Phase I study. This amount of generation was modeled along with all of the optional transmission projects that had been identified for each of the plants.[1]

To determine transfer capability between areas of the System, generation in one area was increased in the model, and generation in the other area was decreased. These changes in generator outputs altered flows over the transmission lines between the two areas. The flows over the lines were monitored as generation levels were changed, until a level of flow was reached such that a single transmission contingency would cause a System component to exceed its acceptable thermal rating. That point then defined the maximum allowable level of transfer between areas.

Scenarios were run to explore the effect of various System projects on the Transmission System's transfer capabilities. Each of nine scenarios (consisting of one or more projects relating to specific facilities) was compared to the Base Case as shown in Appendix B. Cases 6 and 9 of the Phase I Transmission Study

[1] The 6,300 MW value was used by the System in a June 2000 filing with the FERC. The LPSC Staff requested that the same 6,300 MW value be used for the Phase I study.

indicated that potential benefits existed if certain transmission constraints were alleviated.

However, certain limitations of the study process were identified. For example, by the completion of the Phase I study, it was apparent that more than 6,300 MW of merchant generation would be coming on line on the Entergy System. It was also apparent that few of the optional upgrades identified in connection with these new merchant plants and considered in the study would actually be committed to and constructed by the merchant generators. Additionally, the Phase I study utilized three seasonal models (summer, winter and spring/fall) to represent varying load levels over an annual period as opposed to an energy model that represented all 8,760 hours of the year. It was recognition of these limitations that prompted initiation of the Phase II study to better analyze the expansion alternatives identified in Cases 6 and 9 of the Phase I study. These alternatives included projects across the Transmission System in all jurisdictions.

II. Phase II Transmission Study

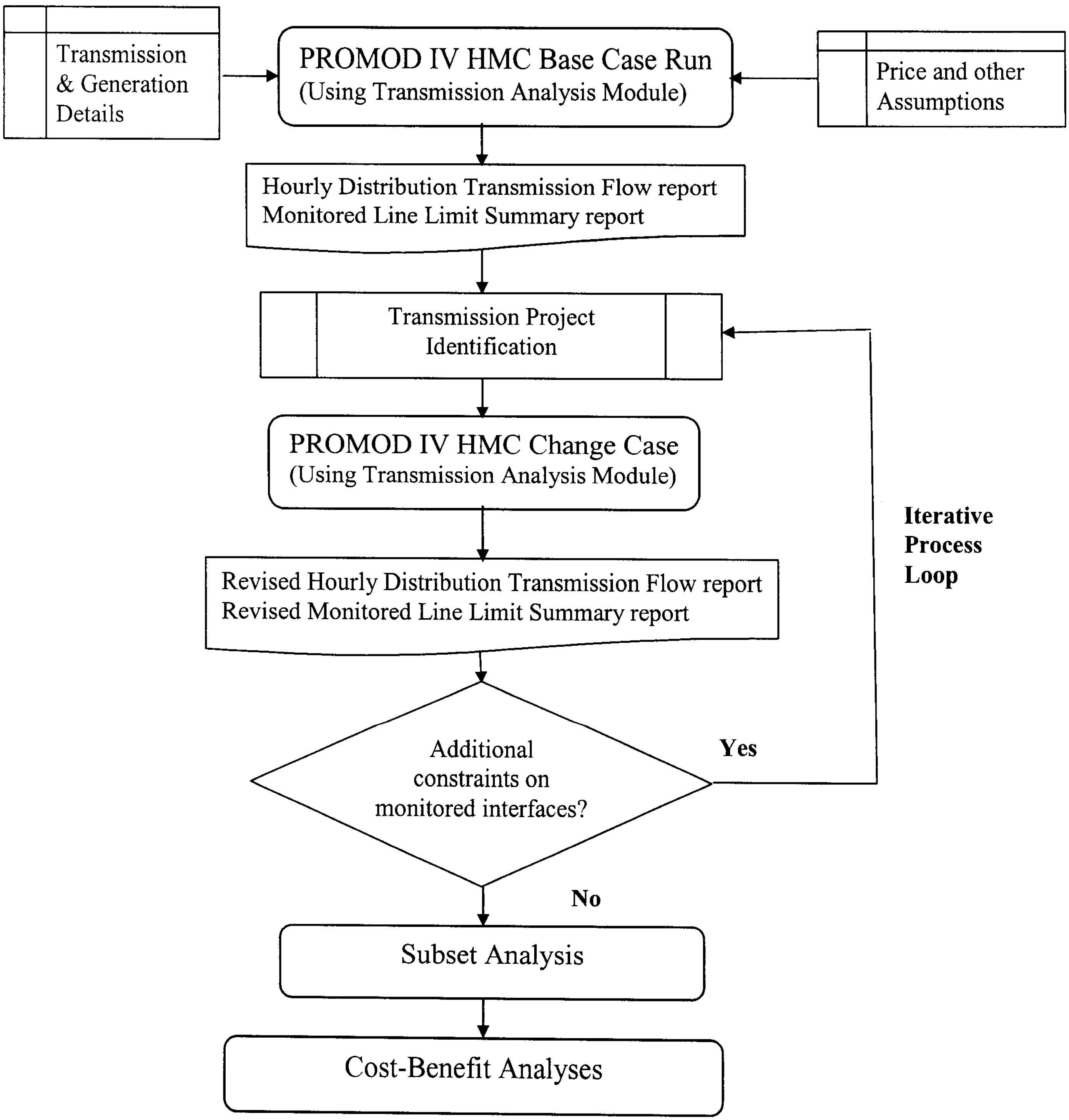
A. Scope

The objective of the Phase II study was to evaluate the benefits to the jurisdictional customers of transmission expansion plans aimed at alleviating internal and external interface limitations associated with Entergy's control area. This effort examined transmission flow patterns based on an economic dispatch of generation in the Entergy control area, and the proposed projects that would be necessary to improve the flow of energy. Transmission alternatives were evaluated using a cost-benefit analysis.

This study was not intended to address the impact of external system flows on the Entergy Transmission System because it was not feasible to perform scenarios on the entire Southeastern United States transmission network. The study also did not evaluate the effects of the implementation of an RTO and real-time congestion management structure. Finally, the study did not focus on identifying transmission projects to enhance export capability.

B. Process Overview

The following flowchart illustrates the major steps for the Phase II Transmission Study.



III. Study Process

A. Transmission System Modeling

The study was initiated by constructing a Base Case transmission model, which represented the interconnected Transmission System over the study period. The Base Case model was required to serve as a benchmark against which transmission alternatives could be evaluated. The model is used in the determination of transmission limitations, in the evaluation of projects to reduce those limitations, and by the PROMOD IV HMC program to perform security constrained economic dispatch for the System. The Base Case transmission model was developed by modifying the topology and load of the summer 2002 model to reflect expected conditions for the summer 2003 and extending through 2012.

In developing the Base Case transmission model for this analysis, the Company incorporated known projects that had been committed to either by the Company or other parties at the time of the study to serve native load. One of the projects which was included and which has a major impact on import capability into the Amite South area is the new 230 kV transmission line from Conway substation to Panama switching station in southeast Louisiana. This circuit is approximately ten miles long and will be constructed using a 1,780 MCM ACSR conductor rated at 1,605 Amps. The in-service date for this project was modeled as December 2004.

The Company also considered in the Base Case those transmission projects for which commitments have been made by the merchant generators within the Interconnection and Operating Agreements. These projects are listed in Appendix C.

The study process differed somewhat from the one presented in the Detailed Work Plan. Analyses were proposed which would determine upper and lower study bounds by running the Transmission System first with no constraints at all on the network, and then with no constraints internal to the Entergy System. PROMOD IV HMC could not reach a solution when no flow limits were imposed on any internal or external interfaces, because it could not dynamically adjust the marginal cost differential. Similarly, PROMOD IV HMC could not reach a solution when flow limits were imposed only on external interfaces, because it could not de-commit the least economic units in the System. Therefore, the Company used existing known constraints on the System (internal and external) as a starting point for this analysis.

B. PROMOD IV HMC Analysis

1. Overview of PROMOD IV HMC program

PROMOD IV HMC is a production-costing model designed to simulate the operation of the Entergy System by economically dispatching the utility's generating resources subject to various unit operating constraints. This model simulates a market with an integrated hourly chronological DC power flow, simulates unit forced outages, and calculates the fuel and purchased power costs to serve the native load and determine the production cost for each Entergy Operating Company.

The PROMOD IV HMC model was chosen because it provides the following features:

- Utilizes an hourly chronological optimal dispatch of available resources given various operational constraints.
- Monitors hourly transmission flows on designated branches given identified contingencies.
- Estimates fuel and purchased power expenses for each Operating Company as well as for the Entergy System by incorporating the terms and algorithms of the Entergy System Agreement accounting logic.
- Models the Transmission System with individual line and bus representation using the Transmission Analysis Module ("TAM").
- Provides hourly locational marginal pricing.

The Transmission Analysis Module in PROMOD IV HMC provides a more detailed depiction of the Transmission System than was available in the prior version of PROMOD by allowing representation of individual transmission facilities (*e.g.*, lines, transformers, phase shifters, etc.). TAM performs a security constrained economic dispatch using a DC load flow for each hour of the study period. However, one of the major limitations of TAM is the run time. It takes approximately twenty hours of computing time to run a ten year simulation while monitoring approximately eighty transmission constraints. Monitoring more transmission constraints may increase computation time significantly.

Other models such as Midas and Prosym were considered as potential alternatives to the PROMOD IV HMC model. Some of the same features listed above are also contained in these and other production costing models. However, the decision to migrate to the PROMOD IV HMC model was primarily based on the Company's existing expertise with PROMOD, the portability of the Entergy System Agreement logic as well as PROMOD's general acceptance by the FERC and each state regulatory commission.

2. PROMOD IV HMC Study Model

The following inputs were considered in developing the PROMOD IV HMC study model:

- PROMOD Topology
- Sales Forecast
- Load Forecast
- Entergy Fossil Units
- Merchant Generation
- Fuel Prices
  - Gas
  - Oil
  - Coal
  - Nuclear (including nuclear characteristics)
- Economy Price Curve
- SO_2 Emissions
- Transactions
  - Hydro
  - Cogeneration
  - Economy Purchases and Sales
  - Summer Purchases
  - Exchange
  - Co-Owner
- Security Region Data
- Transmission
- Simulation Parameters

The detailed descriptions of these inputs are provided in Appendix D.

3. PROMOD IV HMC Base Case Run

The Company used PROMOD IV HMC with TAM to develop the Base Case. This version differs from the prior versions of PROMOD in that the older version used a transportation model (used in Phase I study) while PROMOD IV HMC uses a detailed transmission representation. Inputs to this Base Case include the transmission and generation model details as well as price and other assumptions.

The following set of assumptions was applied in developing the Base Case:

- The Company has included approximately 13,800 MW of merchant generation in the Entergy System. At the start of this study, approximately 12,200 MW were either on-line or had scheduled test power and were scheduled to be on-line by the spring of 2003. The remaining 1,600 MW of generation was scheduled to be on line by the summer of 2004. The Company believed that at the time when Base Case was developed, 13,800 MW represented an accurate projection of merchant generation.
- An off-system "market price" curve was developed that was based upon current market prices.(Detailed description redacted from report)
- The energy prices for merchant plants were modeled using a fuel forecast based on the location of the merchant plant. The fuel price used for a merchant plant was the same price assigned to an Entergy plant located close to that merchant plant.

All other PROMOD IV HMC modeling assumptions are described in Appendix D.

As illustrated by the study process flowchart, the following two reports were generated by the TAM in PROMOD IV HMC for the Base Case run:

- **The Hourly Distribution Transmission Flow Report-** This report displays a histogram of the energy transfers in both directions across the monitored interfaces under the most limiting contingencies.(Example redacted) .
- **The Monitored Line Limits Summary Report-** This report indicates the number of times each monitored interface reached its thermal limit under the most limiting contingency condition, forcing PROMOD IV HMC to redispatch generation. These figures are shown by month for the study period. . (Example redacted)

C. Transmission Project Identification

The Transmission Planning Group initially provided a list of transmission facilities to be monitored in the PROMOD IV HMC Base Case run. These facilities were identified as transfer limits based upon the Company's operating experience, the results of the Phase I study, and various other transmission studies performed by the Company. In subsequent PROMOD IV HMC runs, with the availability of generation dispatch data and feedback from the TAM reports, additional transmission constraints were identified and added to the monitored list. At the completion of this analysis, eighty transmission contingency events and nine interfaces (five internal and four external to the System) were identified as possible limitations to flows across the System and were monitored. A complete list of the transmission facilities that were monitored in PROMOD IV HMC runs is attached in Appendix I. From this list of monitored facilities, the most constraining were ranked as described below.

1. Transmission Constraint Ranking

In the constraint ranking phase of the analysis, the Transmission Planning Group identified those transmission facilities which restricted flows across the Entergy Transmission System. The most constraining facilities were defined as those which reached or exceeded their thermal capability for a significant number of hours, and which had a high marginal cost differential across their corresponding interface over the study period. At the point that a facility reaches its thermal capability, PROMOD IV HMC is forced to redispatch generation around the monitored constraint, thereby increasing the marginal cost differential across the interface associated with the facility.

From the two PROMOD IV HMC reports described above, the Transmission Planning Group determined a ranking of each constrained element. The ranking was based on three criteria:

- The number of hours in which the flow on the transmission element equals or exceeds 95% of the facility's limit.
- The number of hours in which the flow on the transmission element equals or exceeds 100% of the facility's limit.
- The cumulative sum of hourly marginal cost differentials across the constrained element for those hours during which the flow on the transmission element equals or exceeds 95% of its limit.

The Transmission Planning Group identified eleven transmission facilities that consistently exceeded the limits of the first two criteria set forth above and also exhibited significant hourly marginal cost differentials as outlined in criteria three.

The results of the TAM reports indicated that these eleven facilities, as defined above, generally reached or exceeded their thermal capability for more than 3,000 hours over the ten-year study period (87,672 hours total for the study period).

Additionally, the Jacinto to Splendora line was identified as a contingency element. This selection was not because it met the three criteria identified above, but because PROMOD IV HMC could not achieve a successful redispatch when it was constrained, and because the resultant marginal cost differential was relatively high. Therefore, a total of twelve constraining facilities were identified by the Transmission Planning Group to relieve the constrained interfaces. These facilities are listed in Table 1 below.

Table 1. Transmission Constraint Ranking Summary

Contingency Element	Monitored Element	State	Limit (MVA)	Criterion #1. # of Constrained Hours (>95 % Loading)	Criterion #2. # of hours loading reaches 100 % of limit	Criterion #3. Cumulative sum of hourly marginal cost differentials	Constrained Element Rank (1 = Most Constrained, 12 = Least Constrained)
ISES-Newport 161 kV Circuit 1	ISES-Newport 161 kV Circuit 2	AR	417	Confidential Data			2
Willow Glen-Waterford 500 kV	Coly-Vignes 230 kV	LA	462				3
Colfax-Montgomery 230 kV	Beaver Creek 138/115 kV	LA	93				4
Hot Springs EHV West-Friendship 115 kV	Couch-McNeil 115 kV	AR	167				5
McAdams-Lakeover 500 kV	McAdams 500/230 kV	MS	560				6
Nelson-Carlyss 230kV	PPG-Rose Bluff 230 kV	LA	470				7
Ft. Smith 500/345 kV (OGE)	Ft. Smith 500/161 kV(OGE)	AR	480				8
Sheridan-Mablevale 500 kV	White Bluff-Keo 500 kV	AR	1732				9
Grimes-Crocket 345 kV	Jacinto-Peach Creek 138 kV	TX	191				10
Ray Braswell-Lakeover 500 kV	Ray Braswell 500/230 kV	MS	560				11
EastGate-Line533 Tap 138 kV	Jacinto-Splendora 138 kV	TX	206				12

2. Examined Transmission Projects

The Company's Transmission Planning Group identified potential transmission projects to address the constrained interfaces identified in the ranking process. Ten projects which addressed the top eleven constraints were identified. Some of the examined transmission projects address multiple constraints. The lowest ranked constraint, the Jacinto-Splendora 138 kV transmission line, did not meet the ranking criteria. However, because PROMOD IV HMC could not achieve a successful redispatch around this constraint for certain hours in the study period, a transmission project was identified to address only this constraint.

The details of these ten projects are as follows:

- Project No. 1:
  New 161 kV line from ISES to Swifton (Arkansas)

The construction of a fifteen mile line from ISES to Swifton in north Arkansas would address the ISES to Newport 161 kV transmission line constraint. This line would be rated at 448 MVA and was modeled to be in service in March 2005. With the completion of this project, the Change Case model indicated a reduction of approximately 84% in the amount of hours that the System would be constrained by the ISES to Newport line. The estimated cost of this project is $15,125,000.

- Project No. 2:
  New 500/230 kV autotransformer at McAdams (Mississippi)

The installation of a new 500/230 kV, 560 MVA autotransformer would address the existing McAdams 500/230 kV autotransformer constraint. This new autotransformer was modeled to be in service by July 2004. With the completion of this project, the Change Case model indicated a reduction of approximately 83% in the amount of hours that the System would be constrained by the McAdams autotransformer. The estimated cost of this project is $7,560,000.

- Project No. 3:
  New 500/161 kV autotransformer at Fort Smith (Arkansas)

The installation of a new 500/161 kV, 440 MVA autotransformer would address the existing Fort Smith 500/161 kV autotransformer constraint. This new autotransformer was modeled to be in service by July 2004. With the completion of this project, the Change Case model indicated a reduction of approximately 99% in the amount of hours that the System would be constrained by the Fort Smith autotransformer. This facility is owned by Oklahoma Gas and Electric. Therefore, construction of this facility would require coordination with that utility. The estimated cost of this project is $5,940,000.

- Project No. 4:
  New 230 kV line between White Bluff and Woodward (Arkansas)

The construction of a seventeen mile 230 kV line from White Bluff to Woodward in south Arkansas would address the White Bluff to Keo 500 kV transmission line constraint. This project would also include a new 500/230 kV, 560 MVA autotransformer at White Bluff SES. This line would be rated at 521 MVA and was modeled to be in service in April 2005. Although the Change Case model indicates only a small reduction in congestion on the constrained element upon the completion of this project, it would provide an additional path for north to south flows in southern Arkansas, thereby providing additional support to the load in that area. The estimated cost of this project is $32,272,500.

- Project Nos. 5 & 6:
  Rebuild 230 kV line from Coly to Vignes and Rebuild 230 kV Line from Conway to Bagatelle (Louisiana)

The Coly to Vignes line is eleven miles long and the Conway to Bagatelle line is nine miles long. Both are in southeast Louisiana, and rebuilding the lines would address the Coly-Vignes 230 kV transmission line constraint. The Conway to Bagatelle 230 kV line is a tie line between EGSI-Louisiana and ELI-South. The present rating of the Coly to Vignes line is 462 MVA and the line was found to be constrained upon the loss of Willow Glen to Waterford 500 kV line. Upon modeling the capacity of this line at 639 MVA, the Company observed that the constraint would shift to the Conway to Bagatelle 230 kV line. Benefits could only be achieved by rebuilding both the Conway to Bagatelle line and the Coly to Vignes line. These lines were modeled to be in service in July 2005. With the completion of these projects, the Change Case model indicated a reduction of approximately 77% on the amount of hours that the System would be constrained by the Coly to Vignes line. The estimated cost of these projects is $20,250,000.

- Project No. 7:
  Upgrade 138 kV line from Jacinto to Peach Creek (Texas)

The upgrade of the terminal equipment at Jacinto and Peach Creek substations would address the Jacinto to Peach Creek 138 kV line constraint. This project would increase the line rating to 301 MVA. The project was modeled to be in service as of July 2004. With the completion of this project, the Change Case model indicated a reduction of approximately 94% in the amount of hours that the System would be constrained by the Jacinto to Peach Creek line. The estimated cost of this project is $1,053,000. This project has been identified as an optional transmission upgrade. However, no commitment has been made by any party.

- Project No. 8:
  Rebuild 115 kV line from Couch to McNeil (Arkansas)

This project would address the Harvey Couch to McNeil transmission line constraint in southwest Arkansas. Once rebuilt, this fifteen mile line would be rated at 261 MVA. The project was modeled to be in service as of January 2006. With the completion of this project, the Change Case model indicated a reduction of approximately 77% in the amount of hours that the System would be constrained by the Couch to McNeil line. The estimated cost of this project is $10,125,000. This project has been identified as an optional transmission upgrade. However, no commitment has been made by any party.

- Project No. 9:
  Rebuild 138 kV line from Jacinto to Splendora (Texas)

This project would address the Jacinto to Splendora transmission line constraint in east Texas. Once rebuilt, this thirteen mile line would be rated at 411 MVA, and it was modeled to be in service as of July 2006. With the completion of this project, the Change Case model indicated a reduction of approximately 99% in the amount of hours that the System would be constrained by the Jacinto to Splendora line. The estimated cost of this project is $8,775,000. This project has been identified as an optional transmission upgrade. However, no commitment has been made by any party.

- Project No. 10:
  Rebuild 230 kV line from PPG to Rose Bluff (Louisiana)

This project would address the PPG to Rose Bluff transmission line constraint in southwest Louisiana. Once rebuilt, this six mile line would be rated at 797 MVA, and it was modeled to be service as of July 2004. With the completion of this project, the Change Case model indicated a reduction of approximately 82% in the amount of hours that the System would be constrained by the PPG to Rose Bluff line. The estimated cost of this project is $6,075,000. This project has been identified as an optional transmission upgrade. However, no commitment has been made by any party.

A summary of the examined projects is provided in Table 2 below.

Table 2. Examined Transmission Projects Details

No	Examined Transmission Projects	State	Expected Benefit (Location)
1	New 161kV line between ISES and Swifton	AR	Relieve congestion around coal fired Independence units (Near Jonesboro in northeast Arkansas)
2	New 500/230 kV autotransformer at McAdams	MS	Relieve congestion in Entergy's central region. (Near Entergy-TVA border in central Mississippi northeast of Jackson)
3	New 500/161 kV autotransformer at Ft. Smith	AR	Improve North-South interface. (Near Entergy-OG+E border in central Arkansas)
4	New 230kV line between White Bluff and Woodward	AR	Improve North-South interface. (Around Pine Bluff area in south Arkansas)
5	Rebuild 230 kV line from Coly to Vignes	LA	Improve Amite-South interface. (Near Baton Rouge, Louisiana)
6	Rebuild 230 kV line from Conway to Bagatelle	LA	Improve Amite-South interface. (Between Baton Rouge and New Orleans within the Company's industrial corridor)
7	Upgrade 138 kV line from Jacinto-Peach Creek	TX	Optional upgrade for merchant generator. (In east Texas, between Houston and Beaumont)
8	Rebuild 115 kV line from Couch-McNeil	AR	Optional upgrade for merchant generator. (Near Arkansas-Louisiana border)
9	Rebuild 138 kV line from Jacinto to Splendora	TX	Optional upgrade for merchant generator. (Near Louisiana-Texas border around Beaumont area)
10	Upgrade 230 kV line from PPG to Rose Bluff	LA	Optional upgrade for merchant generator. (Near Louisiana-Texas border in Lake Charles area)

For the exact location of these projects, please see Appendix F

D. Revised PROMOD IV HMC Run

After the Transmission Planning Group identified the transmission projects to relieve certain interface constraints, the transmission details were incorporated into PROMOD IV HMC to reflect the proposed improvements in the Transmission System. The Company phased transmission facilities into the transmission models in accordance with their expected in-service dates. A revised PROMOD IV HMC analysis was performed and revised Hourly Transmission Flow reports and Monitored Line Limits Summary reports were generated.

As illustrated in the study process flowchart, the procedure of identifying and evaluating transmission projects was an iterative process that continued until PROMOD IV HMC effectively achieved reasonable transfers on all identified interfaces. A total of three iterations were required to effectively identify the most efficient transmission solution for all of the constrained interfaces identified during the ranking process.

A reasonable transfer was deemed to be achieved, and a transmission project accepted for cost-benefit evaluation either when the constraint was fully relieved or when an unwarranted investment in the Transmission System would be required to achieve additional reductions in the number of constrained hours.(Specific details redacted)

E. Subset Analysis

The purpose of the subset analysis was to identify those transmission projects that might provide a net benefit to the System's customers without the requirement of completing all ten proposed projects. The Company developed a screening process to evaluate subsets of the ten transmission projects. The ranking was determined by comparing an estimate of the production cost savings with the cost associated with each of the projects.

The highest ranked projects were placed in Subset A. These are projects 1, 5, and 6 as shown in Table 3. Subset B comprised the next set of projects in addition to those included in Subset A. Thus, the Subset B projects include projects 2 and 7 in addition to projects 1, 5, and 6. Finally, projects 3, 8, 9, and 10 were added to Subset B to form Subset C. Project 4 was the least economic of the projects and was included in the subset analyses.

PROMOD IV HMC was rerun and a cost-benefit analysis was performed for subsets A, B, and C. These analyses generated a net present value of benefits to the System of all ten projects as well as subsets A, B, and C. For more details on how these subsets were identified, please refer to Appendix G.

Table 3. Summary Development of Subsets of Examined Transmission Projects

No	Project Description	State	Initial Congestion (Hours)	Congestion with Projects Added (Hours)	Est. Project Cost ($)	Subset
1	New 161kV line between ISES and Swifton	AR			15,125,000	Subset A
5,6	Rebuild 230 kV lines from Coly-Vignes and from Conway-Bagatelle	LA			20,250,000	
2	New 500/230 kV autotransformer at McAdams	MS			7,560,000	Subset B
7	Upgrade 138 kV line from Jacinto-Peach Creek	TX			1,053,000	
10	Upgrade 230 kV line from PPG to Rose Bluff	LA	Confidential Data		6,075,000	Subset C
3	New 500/161 kV autotransformer at Ft. Smith	AR			5,940,000	
8	Rebuild 115 kV line from Couch-McNeil	AR			10,125,000	
9	Rebuild 138 kV line from Jacinto to Splendora	TX			8,775,000	
4	New 230kV line between White Bluff and Woodward	AR			32,272,500	Not selected

IV. Cost-Benefit Analysis

For this analysis, an estimate has been made of the total investment necessary to complete the transmission projects. This analysis calculated the annual revenue requirement associated with the investments in the Change Case with all ten examined transmission projects and compared the revenue requirement to the change in the production costs produced by the projects. The end result was the net impact on total cost, *i.e.*, base rate revenue requirement associated with the added investment, net of the change in the fuel and purchased power costs.

After completing the cost-benefit analysis for the full complement of transmission projects, the Company analyzed subsets of the final set of proposed transmission projects to determine the degree to which the individual projects affected the results. More details of this analysis are provided in the next section.

A. Determination of Annual Revenue Requirement

The Company has analyzed the potential net impact of ten specific transmission projects. These consist of new facilities, as well as projects that affect existing facilities. The analysis of the Chang Case estimates the net impact if all ten projects on the System were completed over the three-year period 2004-2006. In addition, three subset analyses were performed. A detailed description of the projects and the combinations analyzed in the subset analyses is contained in Section III.E of this report.

The Change Case analysis consists of ten proposed transmission projects. For each project, an estimate has been made of the total investment necessary to complete the project. The purpose of this section is to describe the calculation of the annual revenue requirement associated with the investment in each of the cases and to compare that revenue requirement to the change in production costs produced by that case. The end result is a net impact on the total cost – base rate revenue requirement associated with the added investment, net of the change in fuel and purchased power costs. These results were calculated for each Operating Company with EGSI-LA and EGSI-TX treated separately and summed to obtain the impact on total System costs.

The annual revenue requirement was determined for each project for each of the years 2004-2026. This revenue requirement consisted of the following:

a) Return on Average Net Investment less accumulated deferred income taxes;
b) Income Taxes;
c) Depreciation Expense;
d) Operation and Maintenance Expense; and,
e) Other Taxes.

1. Return on Average Net Investment

The Transmission Planning Group estimated the total investment needed to complete each of the ten examined transmission projects. Each project had a specific in-service date during the period 2004-2006. Based on the relationship between the depreciation expense associated with transmission and general plant and the average gross investment in transmission and general plant set forth in the System's FERC Transco filing dated December 29, 2000, FERC Docket No. RT01-75-000, a depreciation rate of 2.23% was developed and used to determine the year-by-year net investment. From the average net investment, average accumulated deferred taxes were deducted. The deferred taxes were based on a twenty year tax life and the "MACRS" rates. A rate of return of 10.34% was applied to this net investment to determine the annual return requirement. This rate of return was based on a capital structure of 55% debt and 45% equity, and cost rates of 8.16% applicable to debt capital and 13% applicable to equity capital. These values were obtained from the Entergy Transco filing at the FERC.

2. Income Taxes

A composite federal and state income tax rate of 38.11% was developed and used. Consistent with full tax normalization, this tax rate was applied to the equity component of the return on capital. It was assumed that the entire difference between book and tax depreciation was normalized.

3. Depreciation Expense

The depreciation expense is equal to the gross investment times an annual depreciation rate of 2.23%. The 2.23% depreciation rate is based on the ratio of depreciation expense on transmission and general plant to gross transmission and general plant investment as set forth in the Entergy Transco filing at the FERC.

4. Operation and Maintenance Expenses

The Operation and Maintenance expenses ("O&M") are equal to gross investment times 2.95%. This is the ratio of O&M expenses to gross investment set forth in the Entergy Transco filing at the FERC. In determining the O&M rate of 2.95%, not all Administrative and General ("A&G") expenses were included. Those included were Office Supplies, Outside Services, Property Insurance, Injuries and Damages, and Employee Pension and Benefit expense. These categories constitute 42% of the total A&G expenses set forth in the FERC filing. The O&M expenses for years 2004 through 2026 have been escalated at the rate of 2.5% per year to reflect the effect of estimated inflation.

5. Other Taxes

The Other Taxes expense is equal to the gross investment times 1.46%. This is the ratio of Other Taxes expense to gross investment set forth in the Entergy Transco filing at the FERC. These taxes consist of property, payroll, and franchise taxes.

6. Total Revenue Requirement

For each transmission project, the total revenue requirement was determined for each of twenty years. The revenue requirement for projects below 230 kV was determined separately, and that revenue requirement was assigned to the Operating Company in whose territory the project was located. The revenue requirements of projects at 230 kV and above were summed and allocated based on each Operating Company's estimated load responsibility ratio. For the period 2004-2012, discrete year-by-year load responsibility ratios were used. For the period 2013-2026, the 2007-2012 average load responsibility ratio was used.

B. Determination of the Net Impact of the Transmission Project Analyses

The net impact of the transmission project analyses has been determined by combining the results of the revenue requirement analyses with the results of the PROMOD IV HMC analyses. The PROMOD IV HMC analyses were conducted for each of the transmission project cases for each of the years 2003-2012. The PROMOD IV HMC results with all ten proposed transmission projects were compared to the PROMOD IV HMC Base Case results without any new transmission projects to determine the impact or change in fuel and purchased power costs for each transmission analysis. The change in the fuel and purchased power costs for the years 2006-2012 were averaged. This seven-year average was used to represent the change in each of the years 2013-2026.

The detailed analyses showing the determination of the net impact over the 2004-2026 study period are attached in Appendix H.

- Attachment 1 contains the results for the Change Case analysis with all ten examined transmission projects.

- Attachment 2 contains the results for the Subset A case, which consists of proposed transmission projects 1, 5, and 6.

- Attachment 3 contains the results for the Subset B case, which consists of proposed transmission projects 1, 2, 5, 6, and 7.

- Attachment 4 contains the results for the Subset C case, which consists of proposed transmission projects 1, 2, 3, 5, 6, 7, 8, 9, and 10.

The Net Present Value ("NPV") of the net impacts over the period 2004-2026 was based on an 8.5% discount rate.

The total System fuel and purchased power results were analyzed using standard regression techniques, using an exponential fit. The results of that analysis, as well as the R^2 of the regression, are shown in Table 4 below.

Table 4. Regression Analysis of the Change in Fuel and Purchased Power Costs

Case	Slope	R-Squared
Change Case with all ten projects	1.98%	74.4%
Subset Case A	1.65%	54.2%
Subset Case B	1.57%	35.5%
Subset Case C	1.74%	69.8%

While the R-Squares are not "robust," the slope (trend) or annual percent change is fairly constant for all cases. Consequently, there may be an observable trend. However, one should exercise caution in relying on such a conclusion, because the regression results are based only on seven observations. Given the R-Square values, the use of the average value "X" over the 2006-2012 period as the predictor of future values is as reasonable as the use of the calculated slope, or percent change. However, to test the impact of the calculated trends on the net impact, a further sensitivity analysis was performed. In this analysis, it was assumed that the average value over the period 2006-2012 would increase annually at the rates shown in the table above.

The net impact of the cost and benefits associated with the examined transmission projects is shown in the Table 5 below.

Table 5. Transmission Project Net Benefit Analysis Escalated Change in Fuel and Purchased Power

Case	Annual Escalation Rate	Net Benefit (millions)	Resulting Increase in Net Benefit (millions)
Change Case with all ten projects	1.98%	$144.3	$24.5
Subset Case A	1.65%	$187.9	$15.9
Subset Case B	1.57%	$184.7	$15.8
Subset Case C	1.74%	$190.5	$20.6

V. Study Results

The tables below indicate the Net Present Value of the estimated changes in costs to Entergy customers as a result of the ten transmission projects developed in the Phase II study, as well as the results of three subsets of those projects: A, B, and C. The numbers in the tables indicate that the System overall is projected to receive maximum benefit from subset A, with all jurisdictions receiving some benefits. Subset A consists of the construction of the ISES – Swifton line in Arkansas, and the Coly – Vignes and Conway to Bagatelle lines in southeast Louisiana at an estimated combined cost of $35,375,000

Change Case with all ten transmission projects:

Net Present Value ($000's)

Item	EAI	ELI	EMI	ENOI	EGSI-LA	EGSI-TX	Entergy
Change in Revenue Requirement	($62,114)	($28,091)	($15,107)	($5,954)	($19,217)	($30,458)	($160,941)
Change in Fuel and Purchased Power Costs	$36,844	$110,636	$46,152	$18,943	$52,657	$15,556	$280,788
Net Impact	($25,270)	$82,546	$31,045	$12,989	$33,440	($14,902)	$119,848

Subset A projects:

Net Present Value ($000's)

Item	EAI	ELI	EMI	ENOI	EGSI-LA	EGSI-TX	Entergy
Change in Revenue Requirement	($29,067)	($7,578)	($4,075)	($1,605)	($5,182)	($4,376)	($51,883)
Change in Fuel and Purchased Power Costs	$38,772	$91,829	$32,434	$14,196	$37,146	$9,519	$223,894
Net Impact	$9,705	$84,251	$28,359	$12,591	$31,963	$5,143	$172,011

Subset B projects:

Net Present Value ($000's)

Item	EAI	ELI	EMI	ENOI	EGSI-LA	EGSI-TX	Entergy
Change in Revenue Requirement	($32,049)	($10,842)	($5,831)	($2,298)	($7,417)	($8,046)	($66,483)
Change in Fuel and Purchased Power Costs	$24,209	$99,740	$38,304	$15,779	$43,539	$13,846	$235,417
Net Impact	($7,840)	$88,897	$32,473	$13,481	$36,122	$5,800	$168,933

Subset C projects:

Net Present Value ($000's)

Item	EAI	ELI	EMI	ENOI	EGSI-LA	EGSI-TX	Entergy
Change in Revenue Requirement	($48,726)	($13,407)	($7,210)	($2,842)	($9,173)	($21,979)	($103,338)
Change in Fuel and Purchased Power Costs	$32,913	$110,551	$44,312	$19,045	$51,665	$14,753	$273,239
Net Impact	($15,813)	$97,143	$37,102	$16,202	$42,491	($7,226)	$169,901

Among other factors noted in this report, the results cited above will be affected by the examined transmission projects' in-service dates. One such project, which will have an impact on the Amite South region, is the construction of a 230kV transmission line from Conway substation to Panama switching station in southeast Louisiana. Although the in-service date for this project was modeled as December 2004, it is now expected that this project will be in service by the end of 2005. This delay has been due to right-of-way acquisition issues.

VI. Discussion of Results and Implementation Plan

A. Advancements in the Phase II study

The Phase II Study benefited from improvements in modeling, software, and more up to date data than was available for the Phase I study. With more up to date information on merchant facilities, the optional upgrades that have been committed to, and projects committed to serve native load by Entergy and its neighbors, the PROMOD IV HMC program was better able to define the transmission constraints associated with serving the System load. These improvements enabled the Transmission Planning Group to develop detailed transmission proposals that more directly enhanced the system interfaces than in Phase I. The end result was a list of transmission projects that addressed System requirements as defined within this study.

The PROMOD IV HMC program, used to calculate production costs, represented a significant improvement over the version of PROMOD used in the Phase I Study. The former version of the PROMOD program used a transportation model. With the transportation model, the Entergy System was divided into four discrete areas: Amite South, Wotab, Central, and North Arkansas. Within each of these areas, transmission capability was assumed to be unlimited. Across the interfaces of these areas, the capability of the Transmission System was defined by import and export capabilities calculated by the Transmission Planning Group. Each of these four areas had an import and export capability between itself and each adjoining area, including external utilities as appropriate. The Phase I study was limited to analysis of transfers across the interfaces, and was unable to evaluate flows on individual transmission elements.

The detailed representation of the transmission network enabled PROMOD IV HMC to run load flows within the program. This feature made it possible to dispatch System generation around transmission constraints on an hourly basis. The hourly transmission analysis was an improvement over Phase I, which utilized only one representative hour for each season of the year. There was one model used for summer, one for winter, and one representing spring and fall. PROMOD IV HMC, however, ran an individual model for each of the 8,760 hours of each year of the study. While the Phase I study evaluated a ten year period by performing simulations based on seasonal transmission constraints, the Phase II study generated more accurate results by performing the simulation on approximately 87,600 models over a ten year period.

The detailed transmission network representation within PROMOD IV HMC was also able to generate reports indicating the reaction of the System to varying perturbations of the generating units and transmission facilities. Histograms of power flows across transmission facilities and line limit summaries were generated. These reports indicated System flow capabilities across transmission elements and interfaces; much as the load flow runs do in traditional reliability planning studies. The transmission planners used this information to identify limits, develop proposals to alleviate them, and obtain feedback on the effectiveness of their proposals. Thus, through an iterative process, the planners were able to devise the most effective transmission proposals to target individual concerns.

B. Comparison of results between the Phase I and Phase II studies

The Phase II Transmission Study is an extension of the Phase I study, which estimated benefits to customers of approximately $75 to $80 million by pursuing the transmission plans in either Case 6 or Case 9 of the study. While the overall net benefits between the two studies differ by less than $40 million, major differences were seen in the cost of the transmission projects and in the production cost savings. The gross transmission solutions generated in Phase I, generally involving the addition of 500 kV transmission lines, resulted in construction costs of approximately $170 for Case 6 to $350 million for Case 9. The projects of Phase II, which were better tailored to the constrained interfaces, were less than one third of the cost, ranging from $35 million for Subset A to $117 million for the Change Case with all ten projects. The transmission projects of the Phase II Study are seen to be a more efficient option to enhancing flows across the System. The large reductions in transmission construction costs between the two studies were mitigated somewhat by the lower production cost savings realized in the Phase II Study.

C. Limitations inherent in the Phase II study

Some limitations do exist in the analysis of the Phase II Transmission Study. For example: the TAM solution methodology did not allow for examination of voltage excursions, all lines in the system could not be monitored for overloads because of the extended run time of the program, and the external transmission system (outside of Entergy) was represented in static form.

PROMOD IV HMC used a DC solution methodology when calculating energy flows across the system and dispatching generation around system constraints. The DC solution methodology was necessary to hold the computer run times to a manageable level. Without a DC solution, the PROMOD IV HMC runs would have taken weeks as opposed to the twenty hours typically experienced. As a result, the model did not look at voltages at the generating plants and substations on the system. Any high or low system voltages or system stability issues, which might have occurred as a result of generation dispatch or system contingencies, were not analyzed within the study. Before final acceptance of any of the proposals represented in the Phase II Study, the Transmission Planning Group would have to run individual analyses, using traditional load flow software, to examine the possibility of any voltage or stability concerns in connection with each of the transmission proposals developed within this study.

The long solution time of the model precluded the observation of all lines on the Transmission System for overloads. As was mentioned earlier, over eighty transmissions lines within the Entergy System were monitored for overloads. These were chosen based on the TAM reports and on prior knowledge and studies of the system. But, generation dispatch on neighboring systems was not adjusted to account for perturbations on the Entergy System, and generation dispatch within the Entergy System was not exposed to possible transmission contingencies on neighboring systems. Again, such analysis would require individual investigation of each examined project, and, before final acceptance of any of the proposals represented in the Phase II Study, the Transmission Planning Group would have to run such analyses using traditional load flow software.

D. Differences in the Phase II Study vs. traditional planning

The Phase II study differed from traditional planning studies. Traditionally, planning studies are performed annually by the Transmission Planning Group to develop a Five-Year Plan aimed at delivering energy from designated network resources to the native load. Generation dispatch used in the analysis is provided by Network Customers, who have responsibility for ensuring an adequate supply of energy to meet their native load requirements. The Transmission Planning Group applies that generation dispatch to the System model and designs a transmission network that will deliver the energy to the load under accepted reliability criteria and guidelines.

The Phase II study had no single, well-defined generation dispatch around which the Transmission Planning Group could design a Transmission System. The lack of such a generation dispatch was the result of the excess of generation available for dispatch within PROMOD IV HMC model footprint. Normally, the capacity of the designated network resources closely matches that of the load, so there is a limited set of dispatch options which will accommodate the combination of the two. However, in the Phase II Study, with almost two MW of generation for every MW of load, it was impossible for the Transmission Planning Group to evaluate all possible combinations of generation and load using traditional planning tools.

Additionally, traditional reliability studies only look a few years out into the future. Reliability projects must be justified on a much shorter time frame than was used for the economic evaluation of the Phase II Study. The reasoning behind that practice is the uncertainty surrounding the resources, the load, and the configuration and operation of neighboring utility systems in future years. The Company prepares a Five Year Plan every year, detailing proposed transmission projects to deliver energy from designated network resources to native load. However, projects are not committed to that have projected in-service dates beyond two or three years (enough time to procure right-of-way and construct a transmission line). Contrast, in order to perform a proper economic analysis, it was necessary for the Phase II study to make assumptions and carry out analysis and calculations twenty years into the future. This requirement adds uncertainties to the study results beyond those normally encountered in a planning study focusing on reliability projects.

E. Implementation of the Phase II Study Results

The study methodology of the Phase II Transmission Study helped to better understand the operation of the traditional system constraints and it identified new bottlenecks that could arise as a result of the participation of the merchant generation on the System. However, because of the uncertainty surrounding the results of the Phase II Study, the Company would not commit to construction of the projects identified in this study without further analysis.

Impacts on system voltage and stability could not be determined by the DC solution methodology of the PROMOD IV HMC program, and would have to be evaluated by the Transmission Planning Group using more sophisticated modeling techniques. While the projects showed positive economic results for the dispatch of all merchant units in combination with System units, it is not necessarily certain that such positive results would be attained with less than full participation on the part of the merchant units. Analysis of less than 100 percent participation would have to be made.

The Company recommends that the results of this study be rolled into the transmission planning process, so that the impact of the projects on the reliability of the System can be more fully analyzed and understood. The Five-Year Plan is historically produced in the December-January time frame. The results of the Phase II Analysis could be utilized in the creation of the upcoming Five-Year Plan, so that the reliability impacts of the proposed projects on both Entergy and its neighboring utilities can be evaluated. It would then be possible to commit the appropriate transmission projects in the budget cycle.

APPENDIX A

Entergy Transmission System Map

Click on this URL to view the map (need AutoCAD viewer)

http://oasis.e-terrasolutions.com/documents/EES/Entergy_System_Fiber.dwf

APPENDIX B

Summary of Phase I Transmission Study

SUMMARY OF PHASE I TRANSMISSION STUDY
PREPARED IN RESPONSE TO
LOUISIANA PUBLIC SERVICE COMMISSION
ORDER NO. U-23356

The Phase I Transmission Study analyzed the costs and benefits of completing nine sets of transmission upgrades. The costs consisted of an estimate of the investment costs (return of and on invested capital) and the operating costs (Operations and Maintenance expenses, inclusive of other taxes and insurance). Although the analysis covered the twenty-year period 2002 through 2021, production costs were modeled only for the period 2002 through 2007. The average results over that six-year period were used as the estimated production cost value for each of the remaining years in the study period.

The net effect, defined as the net production cost savings with respect to the Base Case, less the cost of the upgrades, is summarized below. These values reflect the net present value of the results for the 20-year study period using an 8.5% discount rate. Net benefits for the System as a whole are shown as positive numbers, and net increases in costs are shown as negative numbers, *i.e.*, numbers in parentheses.

Transmission Upgrade Case	**Net Benefits/(Net Detriments)**
Amite South Improvements-Case 1	$(111,125,000)
Amite South Improvements-Case 2	$(253,781,000)
WOTAB Improvements-Case 1	$(361,182,000)
WOTAB Improvements-Case 2	$(448,536,000)
North Arkansas Improvements-Case 1	$75,771,000
North Arkansas Improvements-Case 2	$(75,143,000)
System Import Capability Improvements	$(4,346,000)
All Import Improvements-Case 1	$80,673,000
All Import Improvements-Case 2	$(387,084,000)

It was noted that numerous simplifying assumptions were made in conducting these analyses. Thus, the results were considered as reflecting an order of magnitude and not definitive final cost estimates. Investment costs were on a dollar per mile basis rather than being developed by reference to detailed construction cost studies, and thus, was not at an appropriate level of certainty for a planning study. Rather, this was simply a screening analysis. It was assumed that all projects could be in place as of January 1, 2002, and that no problems concerning siting, permitting, right-of-way or easement acquisition, et cetera, would occur. Operating cost estimates were based on existing cost structures for the existing transmission system.

APPENDIX C

List of optional upgrades committed by merchant generators

Appendix C
Committed Optional Transmission Upgrades

Project ID	Merchant Generation Project	Committed System Upgrades
4	Pine Bluff Energy LLC	New 115 kV line from Pine Bluff East Substation to Pine Bluff IP Switching station
		New 115 kV line from Pine Bluff South to Pine Bluff IP Switching Station
		New 115 kV from Pine Bluff IP Switching Station to Pine Bluff IP
9	SRW Cogeneration LP	Bundle 1.46 miles of 138kV Line 549, Dupont #3 to Cow Bulk
		Bundle 1.0 mile of 138kV Line 548, Dupont #3 to Cow Bulk
		Upgrade/replace equipment at Cow Bulk 138/69 kV Substation (includes a 200 MVA transformer, breakers, busses)
		Upgrade Sabine 230kV and 138 kV substations (add 230/138 kV, 300 MVA autotransformer)
		Upgrade 138kV Line 492 (Cow to Sabine)
12	Wrightsville Power Facility, LLC	Wrightsville 115 kV switchyard and 500/115 kV autotransformer
		Upgrade 115kV Mabelvale to White Bluff line (Formerly L.R. Arch St.)
		Upgrade 115kV White Bluff to Mabelvale Line (Formerly L.R. South Line)
		Upgrade 115kV White Bluff to Wrightsville Line (Formerly Lynch Line)
		Upgrade 115kV Little Rock South to Wrightsville Line (Formerly White Bluff Line)
		Upgrade 115kV Lynch to Wrightsville Line (Formerly White Bluff Line)
		Upgrade 115kV Wrightsville-145th Street
		Upgrade 115kV Wrightsville-Lorance Creek Switching Station
		Upgrade 115kV Little Rock Fourche - Little Rock East
		Hot Springs EHV-Replace West Bus Transfer Breaker B1560
		Upgrade 115kV Arch Street - Lorance Creek Switching Station
13	Occidental (Taft)	Upgrade 230 kV line from Frisco to Waterford
		Upgrade 230 kV line from Waterford to Union Carbide
		Upgrade 230 kV line from Union Carbide to Hooker
		Upgrade 230 kV line from Hooker to Waterford
16	Duke Energy Hinds, LLC	Build Rex Brown-Miami-Monument Street 115 kV transmission line
		Upgrade Rex Brown Substation
		Upgrade terminal equipment at Miami Substation
		Upgrade terminal equipment at Monument Street Substation
		Upgrade terminal equipment at South Jackson Substation
		Upgrade South Jackson to Rankin Industrial 115 kV transmission line.
		Upgrade Rankin to Pelahatchie 115 kV transmission line
25	Duke Energy Attala, LLC	Upgrade terminal equipment at Bowling Green Substation
		Upgrade terminal equipment at Kosciusko Substation
		Upgrade terminal equipment at Acona Substation
		Upgrade Attala to Kosciusko transmission line
		Upgrade Acona-Bowling Green transmission line
29	Ouachita Power, LLC	Sterlington 115 kV - Marion 115 kV
		Sterlington 115 kV - Meridian 115 kV
		Sterlington 115 kV - Crossett North 115 kV
		Crossett South 115 kV - Meridian 115 kV
		Huttig 115 kV - Marion 115 kV
		Vicksburg 115 kV - Waterway 115 kV
		Huttig 115 kV - Strong 115 kV
		Crossett North 115 kV - Crossett South 115 kV
		Strong 115 kV - Texas East Station "F" 115 kV
		Tex East Station "F" 115 kV - El Dorado East 115 kV
32	The Dow Chemical Company	Construct a second 230 kV transmission line connecting the Company's proposed Choctaw 230 kV Substation to the Addis 230 kV Substation.
		Equipment/Relay upgrades at Addis to accommodate new line.
51	Acadia Power Partners, LLC	Upgrade (Re-sag) Richard-Jennings 138 kV line
55	Warren Power, LLC	Upgrade 115 kV line from N Vicksburg to West Vicksburg
		Upgrade 115 kV line from West Vicksburg to North Vicksburg
		Upgrade 115 kV line from SE Vicksburg to Bovina
		Upgrade 115 kV line from Clinton to Ray Braswell
65	Union Power Partners, L.P.	Upgrade 115 kV line from El Dorado East to El Dorado
		Upgrade 115 kV line from Texas East Terminal to El Dorado EHV
		Upgrade 115 kV line from Donan Substation to Texas East
		Upgrade terminal equipment at Donan Substation
66	Duke Energy Hot Springs, LLC	Upgrade Arklahoma to Carpenter Dam 115 kV
		Upgrade Butterfield to Hot Springs 115 kV

Appendix C
Committed Optional Transmission Upgrades

Project ID	Merchant Generation Project	Committed System Upgrades
		Upgrade Butterfield to Haskell 115 kV
		Upgrade terminal equipment at Carpenter Dam Substation
		Upgrade terminal equipment at Hot Springs 115 kV Substation
		Upgrade terminal equipment at McNeil Stephens 115 kV Substation
		Upgrade terminal equipment at Butterfield 115 kV Substation
		Upgrade terminal equipment at Camden South 115 kV Substation
		Upgrade terminal equipment at Haskell 115 kV Substation
78	Cottonwood Energy Company, LP	New Hartburg Autotransformer 800MVA, 500/230 kV
		New Cypress Autotransformer 750 MVA, 500/230 kV
		New Cypress Autotransformer 300 MVA, 230/138 kV
83	Bayou Cove, LLC	Build connecting line to the Jennings to Richard 138 kV line
90	MDEA	Rebuild 115 kV line from Delta to Shelby
		Upgrade terminal equipment at Shelby Substation
		Rebuild 115 kV line from Shelby to Roundaway
		Upgrade terminal equipment at Roundaway Substation
		Upgrade terminal equipment at Ruleville Substation
		Ruleville - Schlater 115 kV (Upgrade Schlater 2" IP Riser)
		Upgrade terminal equipment at Schlater
		Upgrade terminal equipment at Browning Substation
		Upgrade terminal equipment at Morehead Substation

APPENDIX D

PROMOD IV HMC Input details (Redacted)

PHASE II TRANSMISSION STUDY
PROMOD MODEL INPUT ASSUMPTIONS

Planning Models and Analysis
June 2003

TABLE OF CONTENTS

EXECUTIVE SUMMARY

- The objective of the Phase II study was to evaluate the benefits to the jurisdictional customers of transmission expansion plans aimed at alleviating internal and external interface limitations associated with Entergy's control area. This effort examined transmission flow patterns based on an economic dispatch of generation in the Entergy control area, and the proposed projects that would be necessary to improve the flow of energy. Transmission alternatives were evaluated using a cost-benefit analysis.

- The simulation period for PROMOD is January 2003 through December 2012.

INTRODUCTION

- PROMOD IV Version 8.3.103, executable dated 3/31/03, is a production-costing model designed to simulate the operation of the Entergy system by economically dispatching the utility's generating resources subject to various unit operating constraints. This model simulates a market with an integrated hourly chronological DC power flow, simulates unit forced outages, and calculates the fuel and purchased power costs (production cost) effects on each of Entergy's Operating Companies.

MODEL INPUTS

- PROMOD Topology
- Sales Forecast
- Load Forecast
- Entergy Fossil Units
- Merchant Generation
- Fuel Prices
    - Gas
    - Oil
    - Coal
    - Nuclear (including nuclear characteristics)
- Economy Price Curve
- SO_2 Emissions
- Transactions
    - Hydro
    - Cogeneration
    - Economy Purchases and Sales
    - Summer Purchases
    - Exchange
    - Co-Owner
- Security Region Data
- Transmission
- Simulation Parameters

PROMOD TOPOLOGY

- The Entergy control area consists of 13 areas being modeled, one for each Operating Company (EGSI is split between Louisiana and Texas), 6 co-owners and a merchant company.
- These 6 co-owners are part owners of the Arkansas coal units, Independence and White Bluff. One area is a dummy area for the merchant company.

SALES FORECAST

- PROMOD uses a forecast of hourly loads, in EEI format, by Entergy Operating Company and by Co-Owner. A second set of inputs is the monthly peak and average values for each Operating Company. These values were forecast using a "bottom-up approach", starting first with the development of a retail sales forecast, by revenue class, a separate wholesale sales and company use forecast, and then aggregating those results to input into HELM, the Hourly Electric Load Model. HELM develops the hourly load forecast used in PROMOD.

- The Entergy Retail Sales Forecast for the years 2003-2012 was developed by the Planning Models and Analysis group.

- Retail Sales Inputs
  - Historical sales from 1992-2001 were used in the analysis
  - Monthly Cooling Degree Days (CDD) and Heating Degree Days (HDD) were calculated from Average Daily Temperatures (ADT) for each legal entity. Heating degree days are measured for temperatures below 60 degrees Farenheit ("°F") while cooling degree days are measured for temperatures above 70°F. There are no HDDs or CDDs calculated for those temperatures between 60 and 70 degrees.
  - Econometric variables are supplied by Economy.com. Service area specific variables are provided for each legal entity.
  - The cogeneration assumptions are as follows:

Customer	OPCO	Impacted kW Load	Load Loss Date
	EGSL		
	EGSL		
	EGSL		
	EGSL		
	EGST		
	EGST		
	ELI		
	ELI		
Total Business Plan			

- Model
  - The forecasts are derived using MetrixND, an RER product.
  - The forecast includes Operating Company retail and wholesale load.
- Approval
  - The business unit leaders, along with the commercial and industrial groups at each company, reviewed and approved the sales forecast. Final approval was received from each Operating Company President.

LOAD FORECAST

- The Entergy Load Forecast for the years 2003-2012 was developed by the Planning Models and Analysis group.
  - Inputs
    - The retail sales forecast described in the Sales Forecast Section.
    - A company use forecast that was based on previous year's FERC Form 1 data and escalated by 0.1%.
    - Ten-year typical weather for each jurisdiction based on the years 1992-2001.
    - Transmission and distribution losses were supplied by Entergy's Rate Design group.
    - Jurisdictional load shapes were based on loads and weather for 1998
  - Model
    - The forecasts were derived using HELM, an EEI product.
    - The forecast provides hourly load for each Operating Company and co-owner, including a forecast for EGSI-TX and EGSI-LA.

ENTERGY FOSSIL UNITS

- Unit Capacities
  - Summer and winter capacities were provided by Generation Planning.
    - The summer ratings are those approved by the Operating Committee for the Summer 2002. These ratings were used for each Summer season modeled in the study period.
    - The winter ratings are those approved by the Operating Committee for the Winter 2002/2003. These ratings were used for each Winter season modeled in the study period.

- Maintenance
  - Ten years of scheduled maintenance data were input. Operations Planning collected data from the plants, which included their assumptions for the next 5 years (through Fall 2008). These data were replicated for the remaining 4 year period based on the maintenance schedule 5 years earlier. For example the maintenance schedule for Spring 2010 is the same as the maintenance schedule for Spring 2005.
  - For the near-term, through the Spring 2004, the October 2002 Operations Planning maintenance schedule was utilized.
  - The RTS (returned to service) units were put on maintenance in the model October through April every year of the study since they are assumed to be available to run during the summer months.
  - Planned maintenance information for Cajun 2 Unit 3 was received from Louisiana Generating ("La Gen") through 2012.

- Forced Outage Rates

  - Annual forced outage rates and partial availability rates were calculated for each fossil unit from Generation Availability Data Reporting System ("GADRS") event data for Jan 2000 through Dec 2001.
  - All events that were greater than 350 hours in duration were reviewed by Operations Planning to determine if they should be included or excluded from the forced outage rate calculation. Based on that review (to determine if the event was recurring or non-recurring in nature), some events were removed from the calculation.
  - A forced outage rate calculation was done for Cajun with GADRS data that was made available from La Gen.

ENTERGY FOSSIL UNITS

- Other Fossil Unit Characteristics
  - Mean time to repair (average forced outage hours) – Based on the average of 2000 and 2001 data. If that value was less than the minimum downtime, the mean time to repair was increased to the minimum downtime.
  - Ramp rates – Provided by Operations Planning in June 2002.
  - Heat rate coefficients – Provided by Operations Planning.
  - Dispatch penalty factors – an average of the 2000 and 2001 amounts used in the ISB process.
  - Start-up energy requirements – Provided by Generation Assets in June 2002.
  - Accounting heat rates – The most recently available annual average heat rates (2001) for each unit from ISB were used for unit accounting heat rates for 2002. For the years 2003-2012, PROMOD internally calculates the previous year's annual average heat rate to use for the current year's accounting heat rate for the purpose of billing exchange energy.

MERCHANT GENERATION

- A total of 19,281 MW of merchant unit generation based on Corporate System Planning's October 11 base case outlook became the starting point for our analysis. Adjustments were made to that total to reflect border plants, cogeneration customers and cancelled plants. The result of these adjustments led to our merchant plant modeling assumption of 13,826 net MW. Those cogeneration projects that had an on-line date during the last quarter of 2001 were still reflected as a merchant plants because very little of that generation would have been reflected in the cogeneration purchase assumption used in PROMOD.

- Other new build capacity (2002 forward) was adjusted to net out the load forecast for that location, leaving only the "merchant" capacity available for dispatch in PROMOD.

- A forced outage rate of 5% and a maintenance outage rate (MOR) of 5% were assumed (EPI's portion of Ritchie 2 and Independence 2 is based on historical data with no MOR). Minimum downtime/runtime is 8/16 (representing on-peak and off-peak hours) for combined cycle and 1/1 for combustion turbine merchant units. The mean time to repair was input as 8 hours.

- Generation Planning split the merchant generation into 3 groups, CT, CC, and COGEN, and defined a heat rate at full load for each group. An additional adjustment was made to the merchant units' heat rates using the heat rate performance factor input.

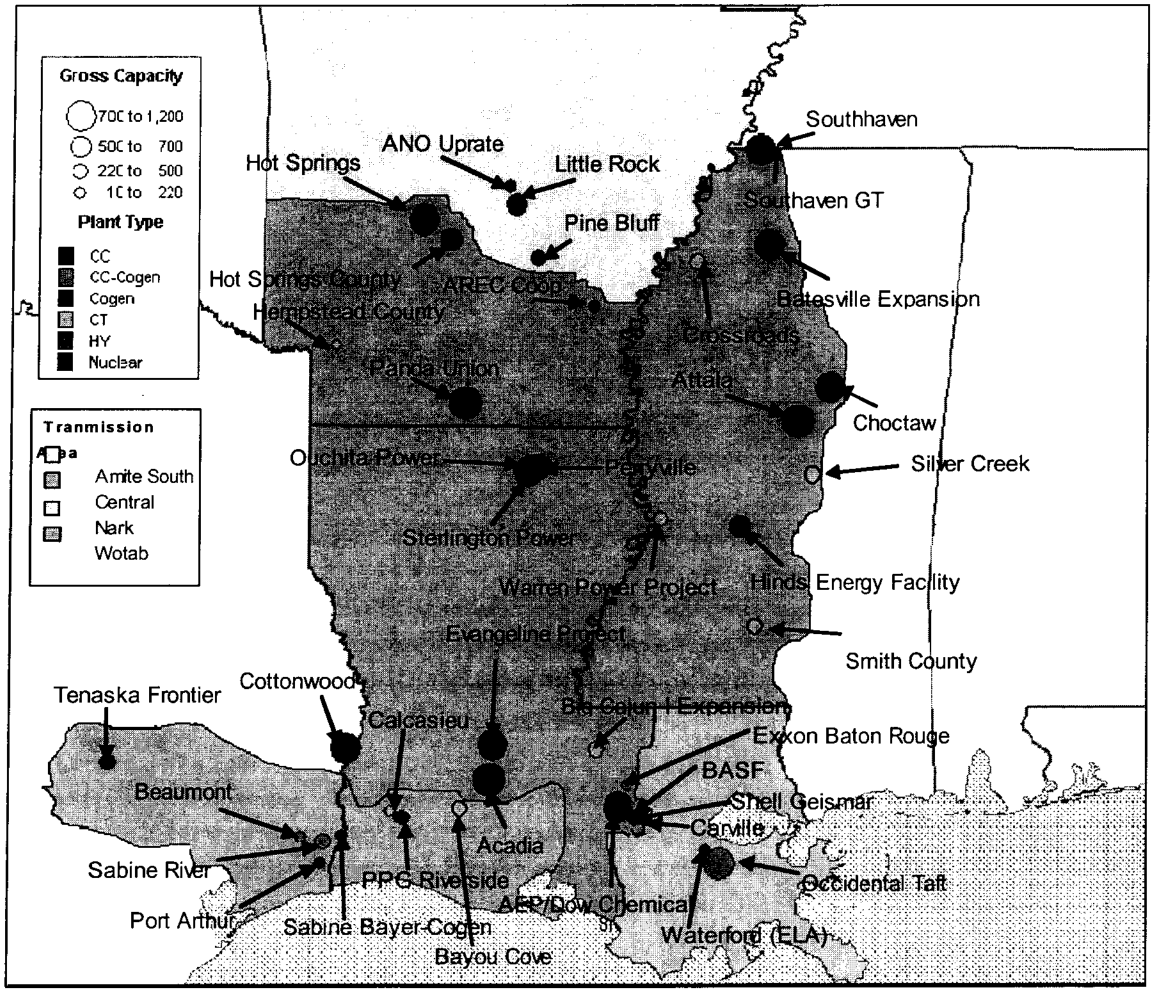
- Generation Planning provided startup cost and variable O&M cost (roughly $1/MWh) utilized in the model.

- A merchant company (Merchco) was established, owning 100% of all merchant generation. Unit purchase transactions were set up for each merchant unit (and EPI's portion of Independence 2 and Ritchie 2) to allow Entergy to purchase the energy that Merchco does not sell off-system. These transactions are treated as joint account purchases and, as such, are split among the Operating Companies by responsibility ratio. The price of the energy sold to Entergy is the bus price for this unit.

- Uplift (dollars) is calculated outside the model by calculating the difference between the merchant unit operating cost (calculated from average heat rate + startup cost + variable O&M cost) and market price (merchant unit transaction price based on incremental heat rate). The distribution to Operating Company is based on kWh sales. Merchant unit profit is ignored in the calculation. Finally, merchant plant uplift is reduced by the percentage of load serving off-system sales.

MERCHANT GENERATION

Below is a map of the Entergy Market Region new builds and capacity uprates assumed in PROMOD.



MERCHANT GENERATION

- Capacity Additions by transmission region, in gross and net MW's, for the Entergy Market Region are displayed below:

Base Case (Most likely Scenario) - NewBuild Capacity in Annual Gross MW by Online Year

TransArea	1999	2000	2001	2002	2003	2004	Grand Total
E_AMITE	0	0	0				
E_CENT	352	1,587	2,015				
E_NARK	0	0	224				
E_WOTAB	19	605	665				
Grand Total	371	2,192	2,904				

This is the starting point for the data input into PROMOD. Reductions were made to this total to reflect the fact that certain plants reside on the border of more than one control area, some of these plants are cogeneration facilities and, therefore, total plant capacity was reduced by an assumed load at that facility or those facilities are already reflected as a cogen purchase in PROMOD. The adjusted totals are reflected on the following two pages.

MERCHANT GENERATION

	Resource Plan Detail	Plant Name	Unit	TCS	Capacity	UCAP COMMENT--TIES TO:	Area	Comm Date
CURRENTLY MODELED AS UNIT							3	1/1/03
TOTAL AMITE								
CENTRAL								
CURRENTLY MODELED AS UNIT				2005			3	1/1/03
CURRENTLY MODELED AS UNIT							1	1/1/03
CURRENTLY MODELED AS UNIT				2005			3	1/1/03
CURRENTLY MODELED AS UNIT				2003			2	1/1/03
CURRENTLY MODELED AS UNIT				2003			2	1/1/03
CURRENTLY MODELED AS UNIT				2005			3	1/1/03
CURRENTLY MODELED AS UNIT				2004			4	1/1/03
CURRENTLY MODELED AS UNIT				2003			2	1/1/03
NEW UNIT				2004			3	1/1/03
CURRENTLY MODELED AS UNIT							1	1/1/03
CURRENTLY MODELED AS UNIT				2003			2	1/1/03
CURRENTLY MODELED AS UNIT							4	1/1/03
CURRENTLY MODELED AS UNIT				2003			3	1/1/03
CURRENTLY MODELED AS UNIT							3	1/1/03
CURRENTLY MODELED AS UNIT				2003			1	1/1/03
CURRENTLY MODELED AS UNIT				2003			3	1/1/03
CURRENTLY MODELED AS UNIT				2003			1	3/1/03
CURRENTLY MODELED AS UNIT				2004				6/1/03
CURRENTLY MODELED AS UNIT				2003			1	4/1/03
CURRENTLY MODELED AS UNIT				2003			1	5/1/03
CURRENTLY MODELED AS UNIT							4	10/1/03
NEW UNIT				2004			1	7/1/04
TOTAL CENTRAL								

MERCHANT GENERATION

NARK								
CURRENTLY MODELED AS UNIT							1	1/1/03
CURRENTLY MODELED AS UNIT				2003			1	1/1/03
TOTAL NARK								
WOTAB								
CURRENTLY MODELED AS UNIT							4	1/1/03
CURRENTLY MODELED AS UNIT							4	1/1/03
CURRENTLY MODELED AS UNIT				2003			4	1/1/03
CURRENTLY MODELED AS UNIT				2003			4	1/1/03
CURRENTLY MODELED AS UNIT							4	1/1/03
CURRENTLY MODELED AS UNIT							4	5/1/03
TOTAL WOTAB								
TOTAL MERCHANTS CURRENTLY MODELED								

RETIREMENTS

- We are currently not modeling the retirement of generating unit in this study.

GAS FORECAST

- The gas forecast in PROMOD is based on the October 1, 2002 forecast for Henry Hub gas prices.
- The annual Henry Hub price forecast is as follows:

- Using the above Henry Hub forecast, EMO's Resource Planning developed a "delivered to plant" gas forecast using the following methodology:
    - For EGSI's generating plants located in Texas, the Houston Ship Channel (HSC) is the appropriate market center. The spot gas forecast for the HSC was based on the historic difference ("basis") between the Henry Hub and HSC. A monthly basis forecast was developed from this historic difference and applied to the forecasted Henry Hub price to arrive at the forecasted spot gas price in the Houston Ship Channel. The projected delivered price of fuel was calculated using the projected index price (Henry Hub or Houston Ship Channel) and any applicable transportation costs, taxes, and, in the case of Evangeline, contract adders/fees.

OIL FORECAST

- A commodity oil price forecast was received from Corporate System Planning in October 2002. The forecasted price was adjusted for transportation and state sales taxes. This formed the basis for determining the dispatch price for oil. The forecast is as follows:

Base Case Oil Price Forecast Annual (Gulf Cost Delivery, $ Per MMBtu) As of 10/2/02

1% Sulfur Residual Fuel Oil $/MMBtu			3% Sulfur Residual Fuel Oil $/MMBtu			Distillate Fuel Oil #2 $/MMBtu			
Year	Nominal	Real 2002$s	Year	Nominal	Real 2002$s	Year	Nominal	Real 2002$s	Notes
1996	$2.77	$ 3.09	1996	$2.47	$ 2.76	1996	Not Available At This Time		Historical Actual
1997	2.55	2.79	1997	2.30	2.52	1997	Not Available At This Time		Historical Actual
1998	1.92	2.07	1998	1.54	1.67	1998	Not Available At This Time		Historical Actual
1999	2.42	2.57	1999	2.27	2.41	1999	Not Available At This Time		Historical Actual
2000	4.13	4.31	2000	3.31	3.45	2000	Not Available At This Time		Historical Actual
2001	3.44	3.52	2001	2.73	2.79	2001	Not Available At This Time		Historical Actual
2002			2002			2002			
2003			2003			2003			
2004			2004			2004			
2005			2005			2005			
2006			2006			2006			
2007			2007			2007			
2008			2008			2008			
2009			2009			2009			
2010			2010			2010			
2011			2011			2011			
2012			2012			2012			

- The oil billing price is based on the projected cost of oil burned out of inventory. The following assumptions are made in the oil inventory forecast:

1. Most recent actual oil inventory accounting summary was provided by Fuel Accounting, and this serves as the starting point for the inventory forecast.
2. EGS maintains its own fuel oil inventory. Fuel oil for all other operating companies is managed by SFI.
3. Oil inventories were maintained by oil type, and all oil was aggregated by type. For example, all #2 oil at EGS plants is aggregated for inventory accounting purposes, regardless of which plant the oil is physically located. Likewise, all #6 EGS oil was aggregated for inventory accounting purposes. This same accounting treatment was followed for SFI oil.
4. If firm oil purchases can be identified, these are included in the inventory forecast, both as to volume and price.
5. Projected oil burns were provided by PMA based on projected dispatch gas and oil prices.
6. It was assumed that oil is purchased in the same volumes as the projected quantities burned. This ensures that oil inventory levels remain unchanged. The price of oil purchased is determined on the basis of the projected spot oil price, including transportation and taxes.

The volume and cost of oil purchased (#6 above) was input into the inventory forecast, along with the volume of oil burned (#5 above), and the cost of oil burned was calculated based on average inventory cost. The result is the average price of oil, by type and by EGS or SFI

COAL FORECAST

- Forecasts of the individual components of the delivered cost of coal were prepared for White Bluff, Independence, and Nelson 6. The individual components included the commodity cost of coal, the cost of transportation, and other coal-related costs such as the cost of company-owned or leased railcars, the operating and maintenance costs associated with coal handling and ash disposal equipment. The forecast for delivered coal costs for Entergy's ownership share of Big Cajun 2, Unit 3 was prepared on a total delivered cost basis because the Company only is provided the sum of coal, transportation, coal car, and car maintenance costs by Louisiana Generating, the majority owner of that facility. The commodity coal cost forecast was provided by Energy Ventures Associates ("EVA"). The forecast for other cost components was based on contract specific terms and conditions or historical data. The coal price forecast was provided by Generation Planning in October 2002.

- A ten-year monthly coal burn assumption for ISES, White Bluff, and Nelson 6 was received from the coal group to develop the fuel limits. For the coal units that burn a combination of contract and spot coal (ISES and White Bluff), Planning Models and Analysis ("PMA") calculated a percentage of total burn by year that would come from contract coal and applied that factor to each month's forecast to get a monthly burn quantity split between contract and spot coal.

- The monthly burn for each coal unit, provided by Coal Supply was sent to Generation Planning. Generation Planning re-priced the coal burn and developed an inventory price that approximated current coal inventory accounting procedures. Generation Planning then gave PMA a single monthly price (calculated from the contract and spot burn quantities and their respective prices) by unit to be used as the coal billing price.

NUCLEAR FORECAST

- The nuclear fuel price forecast, planned maintenance\refueling schedule, heat rates, and capacity changes\uprates were provided by the Nuclear Fuels group. The following is the case description provided by the nuclear fuels group:

Item	Description
Date:	November 11, 2002
Case:	RP-2002-V6-11102002
Schedule:	EN SW Official Schedule 2002 Update #3 approved on 11/06/2002.

- The total monthly fuel cost was used for the dispatch price. Only the variable cost portion was used as the billing price with the fuel related fixed cost dollars input monthly as fixed O&M. 10 percent of Grand Gulf capacity is modeled as a unit participation sale (representing the SMEPA ownership portion); therefore, 90 percent of the Grand Gulf fuel related fixed cost is modeled.

- Coast down data, which is the data that is used to replicate the operation of a unit prior to a nuclear fuel outage, is modeled as a capacity derate in PROMOD prior to the applicable refueling outage for those units such data was provided.

- The mean time to repair (average forced downtime hours) input was derived based upon the following calculation: (8760 [annual hours]*.02 [annual forced outage rate])/2 [number of startups].

- Minimum downtime and runtime inputs were based on an estimate from the nuclear fuels group.

SO2 EMISSIONS

- An annual SO_2 allowance price forecast was received from Generation Planning, based on EVA's long term forecast provided in June 2002.

- Coal unit emission rates from Generation Planning are based on 2001 historical data from the environmental group. Cajun historical data was provided by Louisiana Generating LLC.

- Oil unit emission rates (also provided by Generation Planning) were a theoretical value based on historical data, which varied due to the type of oil burned, and the assumption that we burn only 1% oil in the future.

- From these inputs (the price of SO_2 allowances and unit emission rates), PROMOD adds a dispatch fee to the price of oil and coal.

ECONOMY PRICE FORECAST

- Generation Planning developed an hourly economy price forecast using October 2002 data and the following methodology:
  - SAVA generated monthly forward prices for SOCO and TVA on-peak based on available market quotes as of 10/3/02.
    - Used Entergy price curve from RFP, based on quotes from the same time period.
      - Used historical daily price data from MW Daily and Gas Daily (as far back as 5/97 with significant gaps in data for off-peak prices).
  - Regressions between SOCO and TVA daily on-peak and Entergy daily on-peak price (R-square > 94%).
  - Regressions between SOCO and TVA daily off-peak and Entergy off-peak, SOCO and TVA on-peak (R-square > 67%). Gas price was not a significant variable.
  - Regressions also of seasonal variables where statistically significant. Coefficients also may depend on price level (for example, when Entergy's on peak price is > 137$/MWh, there is a change in the regression model to account for this).
    - On-peak prices from regressions are scaled to match the forward monthly curve.
    - Hourly avoided cost curves for each month were generated from FERC Form 1 data for SOCO and TVA for the year 2001. Also used these data to calculate the Saturday and Sunday daily on-peak price ratios relative to the Friday/Monday average.

ECONOMY PRICE FORECAST

- The price projections, on an annual basis by subperiod, are as follows:

Southern Company $/MWh

Subperiod	Weekday	Weeknight	Weekend
2003			
2004			
2005			
2006			
2007			
2008			
2009			
2010			
2011			
2012			

TVA $/MWh

Subperiod	Weekday	Weeknight	Weekend
2003			
2004			
2005			
2006			
2007			
2008			
2009			
2010			
2011			
2012			

Southern Company Implied Heatrate

Subperiod	Weekday	Weeknight	Weekend
2003			
2004			
2005			
2006			
2007			
2008			
2009			
2010			
2011			
2012			

TVA Implied Heatrate

Subperiod	Weekday	Weeknight	Weekend
2003			
2004			
2005			
2006			
2007			
2008			
2009			
2010			
2011			
2012			

TRANSACTIONS

- Hydro
  - Energy - Blakely/Degray, Remmel and Carpenter, Toledo Bend, and Vidalia energy was modeled based on the 2000 and 2001 monthly energy from the intra-system billing records. For Toledo Bend, the monthly energy was adjusted in 2002 and 2003 due to planned maintenance.

  - Capacity – Remmel, Carpenter, and Vidalia capacity are based on the latest summer and winter 2002 approved ratings from Generation Planning. Toledo Bend was modeled as 69 MW representing Entergy's 75% ownership of the unit. The monthly max capacities were adjusted in 2002 and 2003 due to planned maintenance. Blakely/Degray purchase is modeled as 164 MW, while the sale is 143 MW.

  - Energy Cost – Toledo Bend is modeled with a \$21/MWh energy cost per the contract. Blakely/Degray, Remmel, and Carpenter have an energy cost of \$0/MWh. Vidalia is modeled per its contract as follows:

Vidalia Energy Cost	
Year	\$/MWh
1989-1996	65.00
1997	75.00
1998	85.00
1999	100.00
2000	120.00
2001	125.00
2002	130.00
2003	135.00
2004	145.00
2005	155.00
2006	160.00
2007	170.00
2008	180.00
2009	195.00
2010-2013	205.00

TRANSACTIONS

- Cogeneration
  - Cogeneration was modeled as company specific purchases in PROMOD
  - The energy was based on a monthly two-year average of 2000 and 2001 historical data from ISB, which includes total cogen purchased by company by month.
  - The corresponding peak, also obtained from ISB as the monthly maximum purchased, was averaged monthly and input as the contract's maximum capacity
  - Cogeneration was priced at the Entergy zonal price in PROMOD.

- Economy purchases and sales
  - Economy purchase and sales transactions representing seven external interface locations were modeled.
  - Joint account purchases and sales were priced using one of the two zonal hourly price curves according to the bus location of the transaction.
  - Joint account purchases were split among the Entergy Operating Companies by responsibility ratio in accordance with the System Agreement

- Exchange
  - This is the energy that is exchanged among the Entergy Operating Companies. PROMOD performs a total system dispatch for Entergy. If in any hour, an Operating Company has more generation dispatched than its load, then it is referred to as a "long" Company, although this is not a long Company within the meaning of MSS-1. If a company has less generation dispatched than its load, then it is referred to as a "short" Company, although this is not a short Company within the meaning of MSS-1. The "long" Company's extra energy is allocated to a pool of energy called the Exchange. The "short" Company is allocated its needed energy from the Exchange at a price set by MSS-3.
  - It was assumed that EGS-TX would move to competition in January 2004. After this date, EGS-TX no longer would participate in the exchange; however, dispatch still occurred as a total system. EGS-TX continued to sell to or buy from the rest of the Entergy system. The energy was priced at a load-weighted market price for the region.

TRANSACTIONS

- Co-Owner (The Arkansas Co-Owners represented here are AECC, ETEC, Conway, West Memphis, Osceola, and Jonesboro)
  - Performance Entitlement
    - This transaction represents the amount of energy that each Co-Owner is entitled based on the generation from its share of the unit(s) in question and the terms of the contract. This energy is priced pursuant to their ownership agreement.
  - Substitute
    - This transaction represents the amount of energy each Co-Owner is entitled to that does not come from the co-owned units because of the dispatch decision of the majority owner of the unit. For example, if a co-owned unit is not running at maximum because of Entergy's economic dispatch decisions, but is available at maximum, the Co-Owner is entitled to its ownership share of the output of that unit based on the maximum capacity of the co-owned unit. Therefore, some of the energy will be supplied by the co-owned unit and some will come from other EAI resources. All of the energy is priced as if it came from the unit.
  - Replacement
    - This transaction represents the amount of energy above entitlement which the Co-Owner needs from Entergy to supply the energy portion of the Co-Owner's load based on the terms of the contract. This energy is priced based on the terms of the contract and is different for each Co-Owner.
  - Excess
    - The transaction represents the amount of energy that Entergy is required to purchase back from the Co-Owner. For example, if the Co-Owner load is less than the amount of energy they receive through performance entitlement, then Entergy is required to buy back the energy. The energy is priced based on the terms of the contract and is different for each Co-Owner. This energy is referred to as excess purchase energy.

SECURITY REGION DATA

The following security region data is modeled in the current PROMOD database:

- Rex Brown 4 must be committed any time the EMI load is above 1,800 MW. This occurs usually in the months May through September. (Group H in PROMOD data)
- Two of the following three units should be committed due to voltage problems during contingencies. Ninemile 4, Ninemile 5, or Michoud 3. (Group G in PROMOD data)
- At least two of the following four units should be committed due to potential line loading and voltage problems in Lake Charles area during contingencies. Nelson 4, Nelson 6, Sabine 4, and Sabine 5. Also three of these four units are needed for voltage support during summer and winter peak seasons. (Group D in PROMOD data)
- Sabine 4 or Sabine 5 (on 230 kV bus) must be committed due to voltage problems. (Group C in PROMOD data)
- A minimum of three Sabine units are required to be committed for voltage support problems. This includes two Sabine units on the 138 kV bus and one Sabine unit on the 230 kV bus. (Group E and Group C in PROMOD data)
- A minimum of one unit at Lewis Creek must be committed at all times due to voltage support. Furthermore, Lewis Creek 1 and Lewis Creek 2 must be committed during summer for voltage support. (Group A in PROMOD data)
- Ninemile 1, Ninemile 2 or Ninemile 3 must be committed to supply startup steam for Ninemile 4 or Ninemile 5. (Group B in PROMOD data)

TRANSMISSION

- The PROMOD IV model has the distinct advantage of modeling a full DC load flow representation that allows the user to dispatch under electrical grid properties. One of the features of this representation is the model's ability to adhere to flow limits across specified lines and interfaces.

- In order to take advantage of this feature in PROMOD, the PMA group had to download a PSS/E load flow case from the Transmission OASIS site and convert it into PROMOD format. The Summer 2002 load flow scenario was chosen as the starting point from this site. Once downloaded and converted into PROMOD certain "adjustments" had to be made such as:
  - Assign each operating company a power flow zone:
    - Entergy Arkansas, Inc., EAI - 106, 107, 108 (only the non co-owner busses were assigned to EAI.
    - Entergy Louisiana, Inc., ELI - 55, 100, 105
    - Entergy Mississippi, Inc., EMI - 102, 103, 104
    - Entergy New Orleans, Inc., ENOI – 101
    - Entergy Gulf States, Inc. Louisiana, EGSI-LA – 53, 54
    - Entergy Gulf States, Inc. Texas, EGSI-TX - 50, 51, 52
  - Map each generator and transaction to specific generator busses
  - Input non-conforming load at each load bus. Non-conforming load represents a constant load at a load bus and typically is representative of industrial load. PROMOD takes the current total Company loads (less the non-conforming load) and allocates the load to each bus using the percentage of Summer 2002 PSSE load at each bus (less any non-conforming load at that bus) to total company Summer 2002 load.
  - Add busses to the power flow data to model the non-Entergy portion of Nelson 6, River Bend, Grand Gulf, and Cajun 2 Unit 3.
  - Add additional transmission information to update the Summer 2002 load flow study to the Summer 2003 load flow representation.
  - The following internal and external interface definitions were modeled to ensure that the import/export does not exceed the capacities for each interface as follows:

Interface Name	Interface Type	Import / Export
Amite South	Internal	3,000 / 3,000
WOTAB (West of the Achafalaya Basin)	Internal	2,000 / 2,000
Western	Internal	2,500 / 2,500
Arkansas-North	Internal	3,000 / 3,000
Arkansas-South	Internal	3,500 / 3,500
Southern Company	External	2,900 / 2,900
TVA	External	3,700 / 3,700
Ameren	External	430 / 430
OKGE (Oklahoma Gas & Electric)	External	4,000 / 4,000

TRANSMISSION

- The following external interface definitions were modeled to ensure that the import/export does not exceed the capacities for each interface as follows:
- Eighty contingencies were modeled. Selected 500 KV lines were monitored in addition to other possible constrained lines. The following joint account purchase and sale limits, provided by Transmission, were input into PROMOD:

Transaction	Bus		Control Area		Winter		Spring		Summer		Fall
JP-EAIN1	30214		AMRN		488		420		375		444
JP-EMIN	18434		TVA		488		420		375		444
JP-EMIN	18274		TVA		488		420		375		444
JP-EMIS	15104		SOCO		650		560		500		592
JP-EMIS	15132		SOCO		650		560		500		592
JP-EMIS	15107		SOCO		650		560		500		592
JP-WOTAB	55224		OGE		488		420		375		444
Total Import					3902		3361		3000		3554
Transaction	Bus		Control Area		Winter		Spring		Summer		Fall
JS-EAIN1	30214		AMRN		325		280		250		296
JS-EMIN	18434		TVA		325		280		250		296
JS-EMIN	18274		TVA		325		280		250		296
JS-EMIS	15104		SOCO		434		373		333		395
JS-EMIS	15132		SOCO		434		373		333		395
JS-EMIS	15107		SOCO		434		373		333		395
JS-WOTAB	55224		OGE		325		280		250		296
Total Export					2601		2241		2000		2370

SIMULATION PARAMETERS

- Simulation Period: January 2003 to December 2012

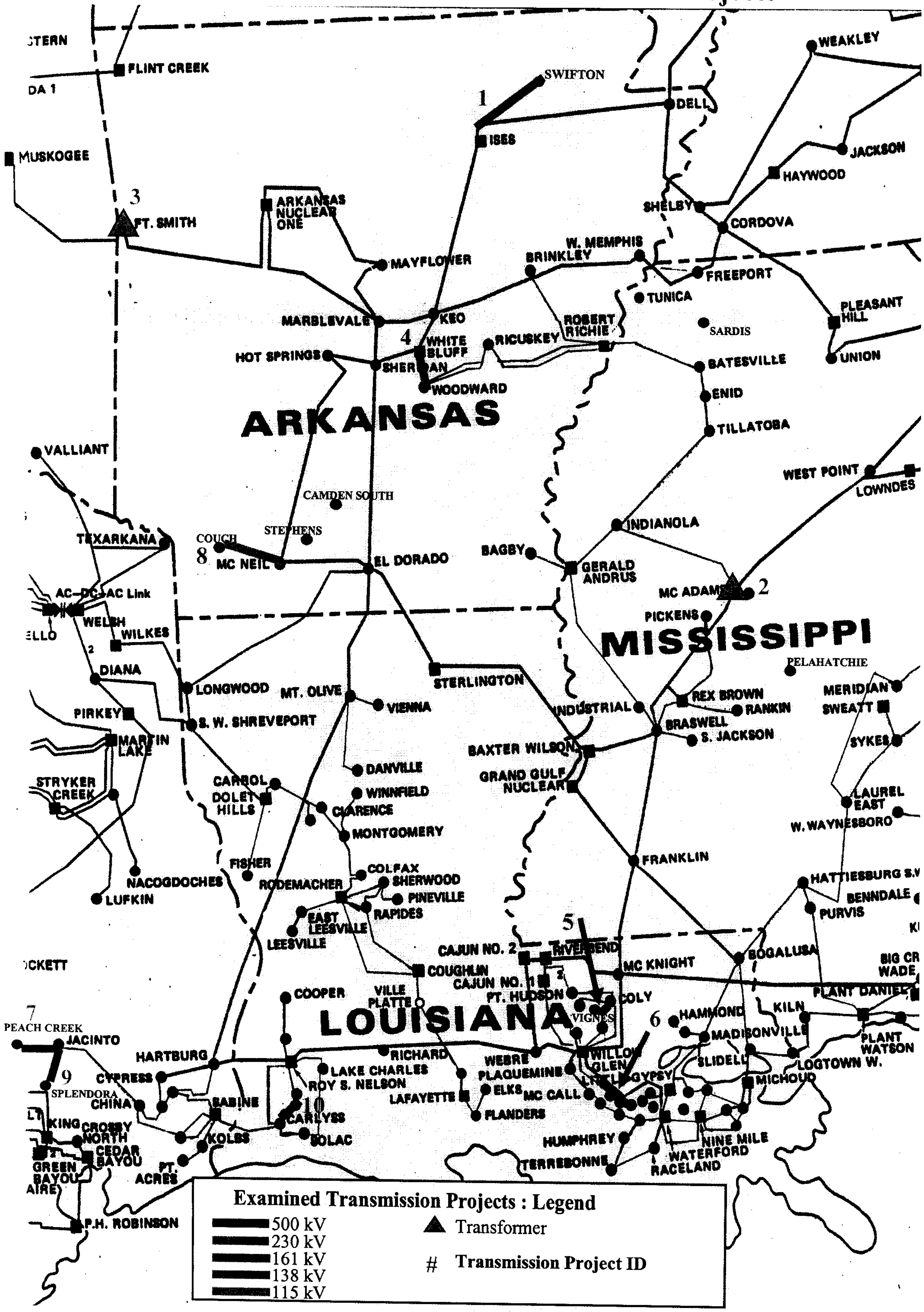
APPENDIX E

PROMOD IV HMC Transmission Results (Redacted)

APPENDIX F

Transmission map indicating location of examined transmission projects

Locations of Examined Transmission Projects



APPENDIX G

Ranking methodology for identifying subset projects

Ranking Methodology for Identifying Subset Projects

As described in the main body of the report, the addition of the ten transmission projects resulted in a reduction in production costs due to the more efficient dispatch of resources within the Entergy control area that is then feasible. These savings are offset by the increase in rate base associated with the capital investment required. If the reduction in production costs exceeds the increase in rates necessary to fund the new project, then there is a net benefit to customers. For each of the ten transmission projects initially identified, the Company compared an estimate of the production cost savings with the capital cost for each of the projects. In the subset analysis, the projects were then ranked based on the ratio of estimated savings to capital costs.

The results from two PROMOD IV HMC runs were used to estimate production cost savings for each project. The first run was with no additional upgrades to the system. The second included all ten identified transmission projects. PROMOD IV HMC provides hourly bus-specific marginal cost information for the transmission system. If there were no redispatch of generation required within the Entergy control area for a particular hour, then PROMOD IV HMC would report the same marginal cost for all busses on the system. As transmission limitations require out-of-merit redispatch of generation, the bus-specific marginal costs diverge. The "congestion" on a particular transmission path is measured as the difference in marginal cost at the busses located at each end of that path. The greater the difference in marginal costs at the busses, then the greater the implied cost differential for units that run out-of-merit on the system. Increasing the capacity of the transmission path would allow the output from the unit setting the marginal cost at the high-priced bus to be reduced and replaced by lower-cost generation setting the bus price at the other end of the path.

For example, if PROMOD IV HMC gives the marginal cost at bus "A" as \$20, and for bus "B" as \$30, increasing the capacity of the transmission path from "A" to "B" by 1MW would allow the output of the \$30 generator that set the cost at "A" to be reduced by 1MW, and the output of the \$20 generator to be increased by 1MW. The net savings is then (30 – 20) = \$10. The more transmission that is added to this path, however, the less the differential is likely to be. Bringing up the cheaper generator by 100MW would likely increase its marginal cost to, say, \$23/MWh, and backing down the more expensive generator by 100MW may reduce its marginal cost to \$27/MWh for our example. The marginal benefit of increasing the transmission path by 101MW (an additional 1MW on top of 100MW assumed already added) is only (27 – 23) = \$4. In general, as more transmission capacity is added to a path, the benefit of the last MW of capacity would be less.

Using the data obtained from the two 10-year PROMOD IV HMC runs, the Company estimated the savings for each of the ten transmission projects. For each of the two runs, the Company then summed the differences in marginal costs for the transmission paths that the transmission projects were intended to relieve so as to get the average congestion cost for each path (in \$/MW-yr) with and without the project. The Company took a simple average of the congestion costs for the two runs and then multiplied this by the estimated transmission capacity that would be added to each path by each upgrade to give the estimated production cost savings for each project.

Using the example above, if we were considering the transmission upgrade that gave 100MW of additional transmission capacity between bus "A" and bus "B", then the average congestion was ($10 + $4)/2 = $7/MW times the number of hours in the year the line would be constrained (say 200) = $1,400/MW-yr. For the 100MW upgrade, the estimated annual production cost savings would be 100MW x $1,400/MW-yr = $140,000/yr.

It should be noted that the estimated savings calculated using this method is used for the ranking of projects in the subset analysis only. The actual savings used in calculating the net benefit of the projects is from the PROMOD modeling runs with the projects included. Cost savings associated with changes in commitment and other operating constraints as well as interactions between the transmission projects can only be measured using PROMOD.

The estimated savings then need to be compared to the capital cost of the project. For each of the ten transmission projects, the Company took the ratio of the estimated production cost savings to the capital costs for the projects and ranked the projects from those offering the greatest benefit for every dollar spent to those giving the least benefit. Again, from our example, if the capital cost of our 100MW transmission upgrade project were $1,000,000, the benefit/cost ratio would be $140,000/$1,000,000 = 14% per year. If we then had another project that would provide savings of $300,000/year but had a capital cost of $20,000,000, this would give a benefit/cost ratio for the project of $300,000/$10,000,000 = 3%, and we would rank the first project over the second.

The benefit/cost ratios calculated for each of the projects was used by the Company to group the projects.

APPENDIX H

Detailed analyses showing the determination of the net impact over the study period (Redacted)

Page Reference	**Change Case Analysis**	**Subset Case**		
		A	**B**	**C**
Summary of Net Impact	1	1	1	1
Project Revenue Requirement	2-14	2-6	2-9	2-12
Change in Fuel and Purchased Power	15-17	7-9	10-12	13-15
Net Impact – 2004-2026	18-20	10-12	13-15	16-18
Revenue Requirement – EAI Under 230kV	21	13	16	19
Revenue Requirement – EGSI-TX Under 230kV	22	N/A	17	20
Revenue Requirement – Over 230kV	23	14	18	21

APPENDIX I

List of Transmission facilities monitored in PROMOD IV HMC runs

DISCLAIMER

Following transmission facilities were monitored in PROMOD IV HMC runs for this particular study only and are based on the initial transmission study results and company's operating experience. These facilities/interfaces may not be necessarily same as used in other transmission analyses.

Transmission facilities monitored with no contingencies:

MONITORED BRANCH 98544 97314 1* * * * * * * * * * * * ! 6SORR 2 TO 6FRNSTL CKT1
MONITORED BRANCH 98652 50070 1* * * * * * * * * * * * ! 6MICHO TO FRONTST6 CKT1
MONITORED BRANCH 98235 99027 1* * * * * * * * * * * * ! 8MCKNT TO 8FRKLIN CKT1
MONITORED BRANCH 98483 98484 1* * * * * * * * * * * * ! 6HAMMND TO 3HAMMND CKT1
MONITORED BRANCH 98555 98578 1* * * * * * * * * * * * ! 6GYPSY TO 6FAIRVW CKT1
MONITORED BRANCH 97717 97691 1* * * * * * * * * * * * ! 8HARTBRG TO 8CYPRESS CKT1
MONITORED BRANCH 97717 97715 1* * * * * * * * * * * * ! 8HARTBRG TO 6HARTBRG CKT1
MONITORED BRANCH 97691 97690 1* * * * * * * * * * * * ! 8CYPRESS TO 4CYPRESS CKT1
MONITORED BRANCH 97690 97713 1* * * * * * * * * * * * ! 6CYPRESS TO 4CYPRESS CKT1
MONITORED BRANCH 97690 97713 1* * * * * * * * * * * * ! 6CYPRESS TO 4CYPRESS CKT2
MONITORED BRANCH 97689 97696 1* * * * * * * * * * * * ! 6AMELIA TO 6HELBIG CKT1
MONITORED BRANCH 97689 97714 1* * * * * * * * * * * * ! 6AMELIA TO 6CHINA CKT1
MONITORED BRANCH 97716 97714 1* * * * * * * * * * * * ! 6SABINE TO 6CHINA CKT1
MONITORED BRANCH 97715 97718 1* * * * * * * * * * * * ! 6HARTBRG TO 6INLAND CKT1
MONITORED BRANCH 97744 97696 1* * * * * * * * * * * * ! 6GEOTOWN TO 6HELBIG CKT1
MONITORED BRANCH 97692 97633 1* * * * * * * * * * * * ! 4CHEEK TO 4ADAYTON CKT1
MONITORED BRANCH 99340 99627 1* * * * * * * * * * * * ! 8WH BLF TO 8KEO CKT1
MONITORED BRANCH 98930 98935 1* * * * * * * * * * * * ! 8R.BRAS TO 8LAKEOV CKT1
MONITORED BRANCH 98930 98931 1* * * * * * * * * * * * ! 8R.BRAS TO 6R.BRAS CKT1
MONITORED BRANCH 98930 98932 1* * * * * * * * * * * * ! 8R.BRAS TO 3R.BRAS CKT1
MONITORED BRANCH 99027 99028 1* * * * * * * * * * * * ! 8FRKLIN TO 3FRKLIN CKT1

Interfaces (internal/ external) monitored:

INTERFACE Amite South
98544 97331 1
98545 97327 1
98497 15030 1
98480 99069 1
98481 99060 1
98487 99073 1
98489 99066 1
98500 98247 1
98500 98247 2
98502 98462 1
98539 98246 1
98569 98259 1
98591 98268 1
98572 50168 1
End

INTERFACE WOTAB
97717 99162 1
98107 98430 1
98147 98410 1

```
INTERFACE Western
53526 97513 1
97714 97721 1
97478 97476 1
97632 97723 1
97633 97472 1
97690 97697 1
97690 97473 1
97694 97685 1
end

INTERFACE North
98718 99651 1
98759 99306 1
99146 99232 1
99146 99305 1
99148 99295 1
99162 99295 1
99165 99315 1
99171 99280 1
99173 99249 1
99528 99398 1
99565 99333 1
end

INTERFACE Sheridan South
99333 99295 1
99333 99402 1
end


INTERFACE Southern Company
98235 15035 1
98497 15030 1
98880 15028 1
99046 15031 1
end

INTERFACE TVA
98702 18022 1
98707 18009 1
98730 18041 1
98700 18010 1
99742 18008 1
99788 18051 1
98730 18041 1
end


INTERFACE AMRN
99748 30720 1
99773 31534 1
end
```

INTERFACE OKGE
99486 55305 1
end

Transmission Events (flowgates) that were monitored with specific Contingencies:

```
! Event 2
MONITORED BRANCH 98930 98932 1* * * * * * * * * * * ! 8R.BRAS TO 3R.BRAS  500/115 KV
MONITORED BRANCH 98930 98931 1* * * * * * * * * * * ! 8R.BRAS TO 6R.BRAS  500/230 KV
MONITORED BRANCH 98905 98931 1* * * * * * * * * * * ! 6NORTHSD TO 6R.BRAS  230 KV
MONITORED BRANCH 98487 98497 1* * * * * * * * * * * ! 6BOGALUS TO 6ADMSCRK 230 KV
CONTINGENCY
LINE     98930   98935     1        ! Ray Braswell -Lakeover 500 kV Ckt 1
END

! Event 3
MONITORED BRANCH 98701 98703 1* * * * * * * * * * * ! 6 HN LAK  3HN LAKE  230 KV
CONTINGENCY
LINE     18009   98707     1        ! Freeport 500/230 kV Ckt 1
END

! Event 4
MONITORED BRANCH 98930 98937 1* * * * * * * * * * * ! 8R.BRAS TO 8B.WLSN 500 KV
CONTINGENCY
LINE     98930   99027     1        ! Ray Braswell-Franklin 500 kV Ckt 1
END

! Event 5
MONITORED BRANCH 99333 99565 1* * * * * * * * * * * ! 8SHERID TO 8MABEL 500 KV
CONTINGENCY
LINE     99340   99627     1        ! White Bluff to Keo 500 kV Ckt 1
END

! Event 6
MONITORED BRANCH 98930 99027 1* * * * * * * * * * * ! 8R,BRAS TO 8FRKLIN 500 KV
CONTINGENCY
LINE     98937   98952     1        ! Baxter Wilson to Grand Gulf 500 kV Ckt 1
END

! Event 7
MONITORED BRANCH 99163 99164 1* * * * * * * * * * * ! 6MTOLIV TO 3MTOLIVE 230/115 KV
MONITORED BRANCH 99161 99164 1* * * * * * * * * * * ! 3VIENNA TO 3MTOLIVE 115 KV
CONTINGENCY
LINE     99162   99295     1        ! Mt.Olive to El Dorado  500 kV Ckt 1
END

! Event 8
MONITORED BRANCH 99340 99627 1* * * * * * * * * * * ! 8 WH BLF TO 8KEO 500 KV
CONTINGENCY
LINE     99333   99565     1        ! Sheridan to Mablevale  500 kV Ckt 1
END
```

```
! Event 9
MONITORED BRANCH 99295 99333 1* * * * * * * * * * * ! 8ELDEHV TO 8SHERID 500 KV
CONTINGENCY
LINE     99402   99441     1        ! Sheridan to Etta  500 kV Ckt 1
END

! Event 10
MONITORED BRANCH 99402 99441 1* * * * * * * * * * * ! 8HSEHV TO 8ETTA 500 KV
CONTINGENCY
LINE     99295   99333     1        ! El Dorado to Sheridan 500 kV Ckt 1
END

! Event 11
MONITORED BRANCH 98235 99027 1* * * * * * * * * * * ! 8MCKNT TO 8FRKLIN 500 KV
CONTINGENCY
LINE     99027   99073     1        ! Franklin to LS Pike 500 kV Ckt 1
END

! Event 12
MONITORED BRANCH 98235 99027 1* * * * * * * * * * * ! 8MCKNT TO 8FRKLIN 500 KV
MONITORED BRANCH 99174 99182 1* * * * * * * * * * * ! DODSON TO DANVILLE 115  KV
MONITORED BRANCH 99112 99174 1* * * * * * * * * * * ! 3WINFLD TO 3DODSON CKT1
CONTINGENCY
LINE     97717   99162     1        ! Hartburg to Mt.Olive 500 kV Ckt 1
END

! Event 13
MONITORED BRANCH 98235 99027 1* * * * * * * * * * * ! 8MCKNT TO 8FRKLIN 500 KV
CONTINGENCY
LINE     97314   98544     1        ! French Settlement to Sorrento 230 kV Ckt 1
END

! Event 14
MONITORED BRANCH 98235 99027 1* * * * * * * * * * * ! 8MCKNT TO 8FRKLIN 500 KV
CONTINGENCY
LINE     99073   98487     1        ! LS Pike to Bogolusa 500 kV Ckt 1
END


! Event 15
MONITORED BRANCH 98707 18009 1* * * * * * * * * * * ! 6FRPORT TO 8 FRPORT 500/230 KV
CONTINGENCY
LINE     98701   98707     1        ! Horn Lake to Allen 230 kV Ckt 1
END


! Event 16
MONITORED BRANCH 97916 97917 1* * * * * * * * * * * ! 8NELSON TO 6NELSON 500/230 KV
CONTINGENCY
LINE     50150   97917     1        ! Penton To Nelson 230 kV Ckt 1
END
```

! Event 17
MONITORED BRANCH 97916 97917 1* * * * * * * * * * * ! 8NELSON TO 6NELSON 500/230 KV
CONTINGENCY
LINE 97696 97744 1 ! Helbig to Georgetown 230 kV Ckt 1
END

! Event 18
MONITORED BRANCH 97916 97917 1* * * * * * * * * * * ! 8NELSON TO 6NELSON 500/230 KV
CONTINGENCY
LINE 97716 97744 1 ! Sabine to Georgetown 230 kV Ckt 1
END

! Event 19
MONITORED BRANCH 97916 97917 1* * * * * * * * * * * ! 8NELSON TO 6NELSON 500/230 KV
CONTINGENCY
LINE 97714 97716 1 ! Sabine to China 230 kV Ckt 1
END

! Event 20
MONITORED BRANCH 97632 97723 1* * * * * * * * * * * ! 4DAYTON TO 4L533TAP 138 kV
MONITORED BRANCH 97633 97472 1* * * * * * * * * * * ! 4BDAYTON TO 4NULJON 138 kV
MONITORED BRANCH 97690 97697 1* * * * * * * * * * * ! 4CYPRESS TO 4HONEY 138 kV
MONITORED BRANCH 97690 97473 1* * * * * * * * * * * ! 4CYPRESS TO 4RYE 138 kV
CONTINGENCY
LINE 97714 97721 1 ! China-Chjc-Ser (Ducento) 230 kV Ckt 1
END

! Event 21
MONITORED BRANCH 97916 97917 1* * * * * * * * * * * ! 8NELSON TO 6NELSON 500/230 KV
CONTINGENCY
LINE 97716 97925 1 ! Sabine to Bthree 230 kV Ckt 1
END

! Event 22
MONITORED BRANCH 98487 98497 1* * * * * * * * * * * ! 6BOGALUS TO 6ADMSCRK 230 KV
CONTINGENCY
LINE 98808 98935 1 ! McAdams to Lakeover 500 kV
END

! Event 23
MONITORED BRANCH 99490 99491 1* * * * * * * * * * * ! 5RUSL-E TO 5RUSL-S 161 KV
CONTINGENCY
LINE 55305 99486 1 ! Ft.Smith to ANO 500 kV
END

! Event 24
MONITORED BRANCH 98487 98497 1* * * * * * * * * * * ! 6BOGALUS TO 6ADMSCRK 230 KV
CONTINGENCY
LINE 97327 98545 1 ! French Branch to Slidell 230 kV
END

```
! Event 25
MONITORED BRANCH 99817 99764 1* * * * * * * * * * * ! 5ISES TO 5NEWPO 161 KV CKT1
CONTINGENCY
LINE     99817   99764     2        ! ISES to Newport 161 kV ckt 2
END

! Event 26
MONITORED BRANCH 99817 99764 2* * * * * * * * * * * ! 5ISES TO 5NEWPO 161 KV CKT2
CONTINGENCY
LINE     99817   99764     1        ! ISES to Newport 161 kV ckt 1
END

! Event 27
MONITORED BRANCH 97514 97487 1* * * * * * * * * * * ! 4GRIMES  TO 4MT.ZION CKT1
CONTINGENCY
LINE     53526   97513     1        ! CROCKET To GRIMES ckt 1
END


! Event 28
MONITORED BRANCH 98555 98578 1* * * * * * * * * * * ! 6GYPSY TO 6FAIRVW CKT1
CONTINGENCY
LINE    98235    99027    1        !  McKnight to Franklin 500 kV Ckt 1
END

! Event 29
MONITORED BRANCH 98259 98569 1* * * * * * * * * * * ! 6CONWAY TO 6BGATEL CKT1
CONTINGENCY
LINE    97331    98391    1        !  Coly to Vignes 230 kV Ckt 1
END

! Event 30
MONITORED BRANCH 98569 98570 1* * * * * * * * * * * ! 6BGATEL TO 6SUNSHN CKT1
MONITORED BRANCH 98570 98568 1* * * * * * * * * * * ! 6SUNSHN TO 6ROMEVL CKT1
MONITORED BRANCH 98500 98504 1* * * * * * * * * * * ! 6EVGREN TO 6DNLDVL CKT1
MONITORED BRANCH 97331 98391 1* * * * * * * * * * * ! 6COLY TO 6VIGNES CKT1
MONITORED BRANCH 98502 98515 1* * * * * * * * * * * ! 3PLAQMN TO 6MCCALL CKT1
CONTINGENCY
LINE    98246    98539    1        !  Willoglen To Waterford 500 kV Ckt 1
END

! Event 31
MONITORED BRANCH 98881 98891 1* * * * * * * * * * * ! 3PELAHE TO 3RANKIN CKT1
MONITORED BRANCH 98793 98792 1* * * * * * * * * * * ! 3GRNADA TO 3S GREN CKT1
CONTINGENCY
LINE    98809    98810    1        !  McAdams to Attala 230 kV Ckt 1
END

! Event 32
MONITORED BRANCH 99106 50012 1* * * * * * * * * * * ! BEACRK 4 TO 3BVRCRK CKT1
CONTINGENCY
LINE    50033    99116    1        !  Colfax to Montgomery 230 kV Ckt 1
END
```

```
! Event 33
MONITORED BRANCH 98583 98606 1* * * * * * * * * * * * ! 6SPORT TO 6 9MILE CKT1
CONTINGENCY
LINE    98583    98606    2       !  South Port to Nine MIle 230 kV Ckt 2
END

! Event 34
MONITORED BRANCH 98583 98606 2* * * * * * * * * * * * ! 6SPORT TO 6 9MILE CKT2
CONTINGENCY
LINE    98583    98606    1       !  South Port to Nine MIle 230 kV Ckt 1
END

! Event 35
MONITORED BRANCH 98410 98411 1* * * * * * * * * * * * ! 4LIVON TO 4WILBT CKT 1
CONTINGENCY
LINE    98107    98430    1       !  Richard to Webre 500 kV
END

! Event 36
MONITORED BRANCH 97696 97744 1* * * * * * * * * * * * ! 6HELBIG TO 6GEOTOWN CKT1
MONITORED BRANCH 99146 99232 1* * * * * * * * * * * * ! STERLINGTON TO CROSSETT NORTH3 115
KV
MONITORED BRANCH 97920 98046 1* * * * * * * * * * * * ! PPG6 TO ROSE BLUFF6 230 KV Ckt1
CONTINGENCY
LINE    97717    97916    1       !  Hartburg to Nelson 500 kV
END

! Event 37
MONITORED BRANCH 97696 97744 1* * * * * * * * * * * * ! 6HELBIG TO 6GEOTOWN CKT1
MONITORED BRANCH 97689 97696 1* * * * * * * * * * * * ! 6AMELIA TO 6HELBIG CKT1
CONTINGENCY
LINE    97714    97716    1       ! China to Sabine 230 kV
END

! Event 38
MONITORED BRANCH 98555 98578 1* * * * * * * * * * * * ! 6GYPSY TO 6FAIRVW  CKT1
CONTINGENCY
LINE    98544    97314    1       ! Sorrento to French Settlement 230 kV
END

! Event 39
MONITORED BRANCH 98555 98578 1* * * * * * * * * * * * ! 6GYPSY TO 6FAIRVW  CKT1
CONTINGENCY
LINE    98652    50070    1       ! Michoud to Front Street 230 kV
END

! Event 40
MONITORED BRANCH 98909 98911 1* * * * * * * * * * * * ! 3JX-NW* TO 3CLINTN  CKT1
CONTINGENCY
LINE    98930    98935    1       ! Ray Braswell to Lakeover 500 kV
END
```

```
! Event 41
MONITORED BRANCH 98482 98484 1* * * * * * * * * * * ! 3INDEPD TO 3HAMMND  CKT1
MONITORED BRANCH 98483 98484 1* * * * * * * * * * * ! 6HAMMND 230 TO 3HAMMND 115
CONTINGENCY
LINE    98235    99027    1       ! Mcknight to Franklin 500 kV
END

! Event 42
MONITORED BRANCH 98309 98406 1* * * * * * * * * * * ! 6ESSO TO 6DELMONT  CKT1
CONTINGENCY
LINE    98310    98400    1       ! Exxon to Downtown 230 kV
END

! Event 43
MONITORED BRANCH 97929 98043 1* * * * * * * * * * * ! 4MOSSVL TO 4MRSHAL  CKT1
CONTINGENCY
LINE    97921    97925    1       ! Carlyss to Big Three 230 kV
END

! Event 44
MONITORED BRANCH 97689 97696 1* * * * * * * * * * * ! 6AMELIA TO 6HELBIG  CKT1
CONTINGENCY
LINE    97691    97717    1       ! Cypress to Hartburg 500 kV
END

! Event 45
MONITORED BRANCH 97690 97713 1* * * * * * * * * * * ! 4CYPRESS TO 6CYPRESS CKT1
MONITORED BRANCH 97690 97713 2* * * * * * * * * * * ! 4CYPRESS TO 6CYPRESS CKT2
CONTINGENCY
LINE    97715    97717    1       ! Hartburg 230 kV to Hartburg 500 kV
END


! Event 46
MONITORED BRANCH 97708 50098 1* * * * * * * * * * * ! 4TOLEDO TO LEESV  4 CKT1
CONTINGENCY
LINE    99116    50033    1       ! Montgomery to Colfax 230 kV
END


! Event 47
MONITORED BRANCH 98309 98406 1* * * * * * * * * * * ! 6ESSO  2 TO 6DELMONT CKT1
CONTINGENCY
LINE    98246    98390    1       ! Willow Glen to Coly 500 kV
END

! Event 48
MONITORED BRANCH 99197 99486 1* * * * * * * * * * * ! 8P HILL TO 8ANO   CKT1
CONTINGENCY
LINE    99486    99565    1       ! ANO to Mabelvale 500 kV
END
```

! Event 49
MONITORED BRANCH 98724 98737 1* * * * * * * * * * * ! 3SHLBY* TO 3DELTA CKT1
CONTINGENCY
LINE 98759 99306 1 ! Andrus to Bagby 230 kV
END

! Event 50
MONITORED BRANCH 98545 50070 1* * * * * * * * * * * ! 6SLIDEL TO FRONTST6 CKT1
CONTINGENCY
LINE 98246 98539 1 ! Willowglen to Waterford 500 kV
END

! Event 51
MONITORED BRANCH 98545 50070 1* * * * * * * * * * * ! 6SLIDEL TO FRONTST6 CKT1
CONTINGENCY
LINE 98235 15035 1 ! Mcknight to Daniel 500 kV
END

! Event 52
MONITORED BRANCH 99773 96103 1* * * * * * * * * * * ! 5PRTGVL TO 5NEWMAD CKT1
CONTINGENCY
LINE 99742 96035 1 ! Dell to New Madrid 500 kV
END

! Event 53
MONITORED BRANCH 97715 97717 1* * * * * * * * * * * ! 6HARTBRG TO 8HARTBRG CKT1
MONITORED BRANCH 97686 97708 1* * * * * * * * * * * ! 4LEACH TO 4TOLEDO CKT1
MONITORED BRANCH 97689 97696 1* * * * * * * * * * * ! 6AMELIA TO 6HELBIG CKT1
MONITORED BRANCH 97476 97543 1* * * * * * * * * * * ! 4JACINTO TO 4PECHCK# CKT1
CONTINGENCY
LINE 97513 53526 1 ! Grimes to Crockett 345 kV
END

! Event 54
MONITORED BRANCH 98497 15030 1* * * * * * * * * * * ! 6ADMSCRK TO 6HATBG CKT1
CONTINGENCY
LINE 98545 97327 1 ! Slidell to French Branch 230 kV
END

! Event 55
MONITORED BRANCH 55305 55300 1* * * * * * * * * * * ! FTSMITH8 TO FTSMITH5 CKT1
CONTINGENCY
LINE 55305 55302 1 ! Ft. Smith 500/345 Transformer (OGE)
END

! Event 56
MONITORED BRANCH 98808 98809 1* * * * * * * * * * * ! 8MCADAM TO 6MCADAM CKT1
CONTINGENCY
LINE 98808 98935 1 ! Mcadams to Lakeover 500 kV
END

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! Event 57
MONITORED BRANCH 99250 97306 1* * * * * * * * * * * ! 3EUDRA TO 3CHKSAW CKT1
MONITORED BRANCH 98764 98836 1* * * * * * * * * * * ! 3HETHSW TO 3BRKYRD CKT1
CONTINGENCY
LINE    98759    98769    1       ! Andrus to Indianola 230 kV
END

! Event 58
MONITORED BRANCH 98867 98946 1* * * * * * * * * * * ! 3VKB-E* TO 3WATERWY CKT1
CONTINGENCY
LINE    98937    98938    1       ! Baxter Wilson 500/115 kV
END

! Event 59
MONITORED BRANCH 98759 98769 1* * * * * * * * * * * ! 6ANDRUS TO 6INDOLA CKT1
CONTINGENCY
LINE    98759    98760    1       ! Andrus 230/115 kV
END

! Event 60
MONITORED BRANCH 97453 97522 1* * * * * * * * * * * ! DOBBIN TO TUBULAR 138 KV
MONITORED BRANCH 97453 97457 1* * * * * * * * * * * ! DOBBIN TO LONGMIRE 138 KV
MONITORED BRANCH 97454 97514 1* * * * * * * * * * * ! WALDEN TO GRIMES 138 KV
MONITORED BRANCH 97454 97469 1* * * * * * * * * * * ! WALDEN TO APRIL 138 KV
MONITORED BRANCH 97469 97470 1* * * * * * * * * * * ! APRIL TO LAKE FOREST 138 KV
CONTINGENCY
LINE     97487    97514    1       ! Mt Zion-Grimes 138 kV Ckt 1
END

! Event 61
MONITORED BRANCH 98708 98709 1* * * * * * * * * * * ! DESOTO TO WALLS 115 KV
MONITORED BRANCH 98705 98720 1* * * * * * * * * * * ! BANKS TO TUNICADIST 115 KV
MONITORED BRANCH 98715 98716 1* * * * * * * * * * * ! SENATOBIA TO SARDIS 115 KV
MONITORED BRANCH 98730 98716 1* * * * * * * * * * * ! BATESVILLE TO SARDIS 115 KV CKT1
MONITORED BRANCH 98719 98720 1* * * * * * * * * * * ! TUNICA TO TUNICA DIS 115 KV
CONTINGENCY
LINE     98707    98710    1       ! Freeport-Robinsonville 230 kV Ckt 1
END

! Event 62
MONITORED BRANCH 98708 98709 1* * * * * * * * * * * ! DESOTO TO WALLS 115 KV
MONITORED BRANCH 98705 98720 1* * * * * * * * * * * ! BANKS TO TUNICA DIS 115 KV
MONITORED BRANCH 98715 98716 1* * * * * * * * * * * ! SENATOBIA TO SARDIS 115 KV
MONITORED BRANCH 98730 98716 1* * * * * * * * * * * ! BATESVILLE TO SARDIS 115 KV CKT1
MONITORED BRANCH 98719 98720 1* * * * * * * * * * * ! TUNICA TO TUNICA DIS 115 KV
CONTINGENCY
LINE     98701    98707    1       ! HornLake-Freeport 230 kV Ckt 1
END

! Event 63
MONITORED BRANCH 99326 99330 1* * * * * * * * * * * ! PINEBLUFF SOUTH TO 34TH & MAIN 115 KV
CONTINGENCY
LINE     99326    99327    1            ! PineBluff South-WatsonChapel 115 kV Ckt 1
END
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! Event 64
MONITORED BRANCH 97854 97855 1* * * * * * * * * * * * ! KOLBS TO LAKEVIEW 69 KV
MONITORED BRANCH 97855 97882 1* * * * * * * * * * * * ! LAKEVIEW TO L189T117 69 KV
MONITORED BRANCH 97856 97882 1* * * * * * * * * * * * ! MANCHST TO L189T117 69 KV
MONITORED BRANCH 97852 97886 1* * * * * * * * * * * * ! GROVES TO PORT NECHES BULK 69 KV
CONTINGENCY
LINE 97867 97885 1 ! Atlantic-Pt. Neches Bulk 69 kV Ckt 1
END

! Event 65
MONITORED BRANCH 97843 97705 1* * * * * * * * * * * * ! PORT NECHES BULK TO SABINE 138 KV
CONTINGENCY
LINE 97701 97705 1 ! Hampton-Sabine 138 kV Ckt 1
END

! Event 66
MONITORED BRANCH 99146 99232 1* * * * * * * * * * * * ! STERLINGTON TO CROSSETT NORTH 115 KV
MONITORED BRANCH 97920 98046 1* * * * * * * * * * * * ! PPG6 TO ROSE BLUFF 230 KV CKT 1
CONTINGENCY
LINE 99306 99261 1 ! Bagby 230/115Autotransformer
END

! Event 67
MONITORED BRANCH 99146 99232 1* * * * * * * * * * * * ! STERLINGTON TO CROSSETT NORTH 115 KV
MONITORED BRANCH 97920 98046 1* * * * * * * * * * * * ! PPG6 TO ROSE BLUFF6 230 KV CKT 1
CONTINGENCY
LINE 97917 97921 1 ! Nelson-Carlyss 230 kV Ckt 1
END

! Event 68
MONITORED BRANCH 99565 99566 2* * * * * * * * * * * * ! MABELVALE 500/115KV TRANSFORMER#2
CONTINGENCY
LINE 99565 99566 1 ! Mablevale500/115kV Transformer #1
END

! Event 69
MONITORED BRANCH 98719 98706 1* * * * * * * * * * * * ! TUNICA TO CRENSHAW 115 KV
CONTINGENCY
LINE 98729 98730 1 ! Batesville-Batesville 230/115 kV Ckt1
END

! Event 70
MONITORED BRANCH 98719 98706 1* * * * * * * * * * * * ! TUNICA TO CRENSHAW 115 KV
!MONITORED BRANCH 98703 98704 1* * * * * * * * * * * * ! HORN LAKE TO PLUM POINT 115 KV
CONTINGENCY
LINE 98729 99680 1 ! 6Batesville to 6Ritchietap 230 kV
END

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! Event 71
MONITORED BRANCH 98780 98786 1* * * * * * * * * * * * ! ACONA TO BOWLING GREEN 115 KV
CONTINGENCY
LINE      98770     98776     1          ! Indianola-Moorhead 115 kV Ckt 1
END

! Event 72
MONITORED BRANCH 98250 98263 1* * * * * * * * * * * * ! ADDIS TO CHOCTAW 230 KV
CONTINGENCY
LINE      98474     98263     1          ! AirLiquide-Choctaw 230 kV Ckt 1
END

! Event 73
MONITORED BRANCH 98941 98942 1* * * * * * * * * * * * ! VICKSBURG TO VICKSBURG-WEST 115 KV
CONTINGENCY
LINE      98866     98938     1          ! SE-Vicksburg-BaxterWilson 115 kV Ckt 1
END


! Event 74
MONITORED BRANCH 99174 99182 1* * * * * * * * * * * * ! DODSON TO DANVILLE 115  KV
MONITORED BRANCH 99112 99174 1* * * * * * * * * * * * ! WINFIELD TO DODSON 115 KV
CONTINGENCY
LINE      97717     99162     1          ! Hartbrg8-Mtoliv8 500 kV Ckt 1
END

! Event 75
MONITORED BRANCH 99230 99310 1* * * * * * * * * * * * ! COUCH TO MCNEIL 115 KV CKT1
CONTINGENCY
LINE      99403     99407     1          ! HotSprings EHV West-Friendship3 115 kV Ckt 1
END

! Event 76
MONITORED BRANCH 97467 97531 1* * * * * * * * * * * * ! TAMINA TO APOLLO 138 KV
MONITORED BRANCH 97476 97534 1* * * * * * * * * * * * ! JACINTO TO SPLENDORA 138 KV CKT1
CONTINGENCY
LINE      97627     97723     1          ! EastGate-L533TP86 138 kV Ckt 1
END

! Event 77
MONITORED BRANCH 97994 98106 1* * * * * * * * * * * * ! LC-BULK TO HEBERT 138 KV
MONITORED BRANCH 98097 98106 1* * * * * * * * * * * * ! BAYOU COVE TO HEBERT 138 KV
MONITORED BRANCH 97994 97918 1* * * * * * * * * * * * ! LC-BULK TO NELSON 138 KV
MONITORED BRANCH 98031 98097 1* * * * * * * * * * * * ! JENNINGS TO BAYOU COVE 138 KV
CONTINGENCY
LINE      97916     98107     1          ! Nelson-Richard 500 kV Ckt 1
END

! Event 78
MONITORED BRANCH 98031 98097 1* * * * * * * * * * * * !JENNINGS TO BAYOU COVE 138 KV
MONITORED BRANCH 98097 98108 1* * * * * * * * * * * * !BAYOU COVE TO RICHARD 138 KV
CONTINGENCY
LINE      98107     97916     1          ! Richard-Nelson 500 kV Ckt 1
END
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! Event 79
MONITORED BRANCH 98745 98746 1* * * * * * * * * * * * ! GREENVILLE N TO GREENVILLE E 115 KV
CONTINGENCY
LINE 98747 98750 1 ! Greenville Midtown-Greenville 115 kV Ckt 1
END

! Event 80
MONITORED BRANCH 98938 99154 1* * * * * * * * * * * * ! BAXTERWILSON TO TALLULAH 115 KV
MONITORED BRANCH 99154 99155 1* * * * * * * * * * * * ! TALLULAH TO DELHI 115 KV
CONTINGENCY
LINE 98937 99203 1 ! BaxterWilson8-Perryvile
END

! Event 81
MONITORED BRANCH 99278 99310 1* * * * * * * * * * * * ! STEPHENS TO MCNEIL 115 KV CKT1
MONITORED BRANCH 99278 99302 1* * * * * * * * * * * * ! STEPHENS TO CAMDEN-S 115 KV CKT1
CONTINGENCY
LINE 99295 99293 1 ! El Dorado EHV8-El Dorado 115 kV Ckt 1
END

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J. Wayne Anderson
Vice President and
Deputy General Counsel
Regulatory

April 4, 2005

***Via* E-Filing**
Hon. Magalie Roman Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Docket No. ER03-583-000, *et al.*, and Consolidated Cases
Entergy Services, Inc. *et al.*

Dear Ms. Salas:

Entergy Services, Inc. ("ESI"), on behalf of Entergy Operating Companies (Entergy Arkansas, Inc., Entergy Gulf States, Inc., Entergy Louisiana, Inc., Entergy Mississippi, Inc., and Entergy New Orleans, Inc.), hereby respectfully submits its Reply Brief.

Sincerely,

/s/ J. Wayne Anderson

Enclosures

cc: Hon. Lawrence Brenner
Presiding Administrative Law Judge (*Via* Federal Express)
Service List (*Via* Electronic Mail, Federal Express, U.S. Mail)